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REPORT ON THE APPLICATIONS OF TRANS-CANADA PIPE LINES LIMITED AND ALBERTA AND SOUTHERN GAS CO. LTD. UNDER THE GAS RESOURCES PRESERVATION ACT, 1956

NOVEMBER 1964

Alta

OIL AND GAS CONSERVATION BOARD
603 SIXTH AVENUE SOUTH WEST • CALGARY, ALBERTA

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TO THE LIEUTENTANT GOVERNOR IN COUNCIL

REPORT ON THE APPLICATIONS OF TRANS-CANADA PIPE LINES LIMITED AND ALBERTA AND SOUTHERN GAS CO. LTD. UNDER THE GAS RESOURCES PRESERVATION ACT, 1956

NOVEMBER 1964

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I INTRODUCTION

This report deals with applications under The Gas Resources Preservation Act, 1956, of Trans-Canada Pipe Lines Limited and Alberta and Southern Gas Co. Ltd. The former application was heard by the Board on June 9 to June 12, 1964, and the latter application on July 2 and 3 and July 7 to 10, 1964. In deciding to make a joint report on the two applications, the Board considered, not only the proximity of the hearings and the several matters of consideration common to the applications, but also

(a) the request of Northwestern Utilities, Limited and Canadian Western Natural Gas Company Limited at the Trans-Canada hearing that their evidence there be applicable to the Alberta and Southern application upon the understanding that their witnesses would submit to further cross-examination at the later hearing,

(b) the suggestion by Alberta and Southern, at the Trans-Canada hearing, that the Board might well decide to write a single report - not accepted when made, but becoming pertinent after the conclusion of the hearings,

(c) the request of Trans-Canada, at the end of the Alberta and Southern hearing, that submissions and evidence in the Alberta and Southern application be made applicable to the Trans-Canada application.

Trans-Canada holds Permit No. TC 64-5 authorizing the removal from the Province of 9.640 trillion cubic feet of gas at 14.65 pounds per square inch absolute and 60 degrees Fahrenheit. Alberta and Southern holds Permits numbered AS 59-1 and AS 60-2 which in aggregate authorize the removal from the Province of 4.200 trillion cubic feet of gas at 14.4 pounds per square inch absolute and 60 degrees Fahrenheit, being equivalent to 4.128 trillion cubic feet of gas at 14.65 pounds per square inch absolute. Throughout this report, unless otherwise indicated, volumes will be referred to a pressure base of 14.65 pounds per square inch absolute.

Trans-Canada Application

In its application, Trans-Canada asked for a new permit authorizing removal from the Province of 2.150 trillion cubic feet from the Edson, Hespero and Medicine River fields during a term ending October 31, 1989. It asked also for amendments to its subsisting Permit No. TC 64-5 increasing the total volume of gas from 9.640 trillion cubic feet to 9.970 trillion cubic feet. Finally, it requested consolidation into one permit of Permit No. TC 64-5 and the new permit applied for. The consolidated permit would authorize the removal of 12.12 trillion cubic feet. (inclusive of gas removed to date).

Appearing for the applicant were N. J. McNeill, Q.C. and R. J. Ludgate.

Alberta and Southern Application

Alberta and Southern applied for amendment of Permit No. AS 59-1 by deleting from the Schedule of Fields therein "Parkland Field" and adding to the Schedule "Willesden Green Field, Sundre Field and Sylvan Lake Field". It applied also for an amendment to Permit No. AS 60-2 by adding to the Schedule of Fields therein "Grizzly Field, Hunter Valley Field, North West Pine Field, Raven River Field, Wildhorse Creek Field and Wilson Creek Field". Finally it requested that the two subsisting permits, each as amended, be consolidated into one permit providing for the removal over a period ending October 31, 1989 (extended from October 31, 1986) of gas totalling 6.450 trillion cubic feet (inclusive of gas removed to date which is an increase from 4.128 trillion cubic feet). It requested that the consolidated permit make provision for increasing the stipulated maximum day limitations of the permit to 110 per cent of the stipulated volume for the purpose of alleviating temporary operating problems.

At the hearing of the Alberta and Southern application, R. A. MacKimmie, Q.C. appeared for the applicant.

II INTERVENERS

The following registered as interveners at the hearing of the Trans-Canada application:

Interveners	Represented by	Abbreviation of name used in Report
Alberta and Southern Gas Co. Ltd.	R. A. MacKimmie, Q.C. and J. R. Smith	Alberta and Southern
Canadian Pacific Oil and Gas Limited	D. B. Hodges	Canadian Pacific
Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited	G. H. Steer, Q.C. and B. V. Massie, Q.C.	Utilities Companies (when referred to together)
Hudson's Bay Oil and Gas Company Limited	R. E. Armitage	Hudson's Bay
Pan American Petroleum Corporation	B. J. Todesco	Pan American
Royalite Oil Company, Limited	G. A. Connell	Royalite
Triad Oil Co. Ltd.	J. R. Lacey	Triad
City of Calgary	S. J. Helman, Q.C. and F. J. Fleming	
City of Edmonton	A. F. MacDonald, Q.C.	
Canadian Industrial Gas Limited	C. M. Leitch and R. A. F. Montgomery	Canadian Industrial
The Alberta Gas Trunk Line Company Limited	W. A. Howard, Q.C.	Trunk Line
Hamilton Brothers Canadian Gas Company Ltd.	S. Cunningham R. F. Emerson	Hamilton Brothers
Sherritt Gordon Mines Limited	W. H. Young	Sherritt Gordon
Independent Petroleum Association of Canada	J. Pletcher	IPAC
Uno-Tex Petroleum Corporation	K. W. Germond H. C. Lowther	Uno-Tex
Shell Canada Limited	C. R. Fetherston	Shell
Canadian Petroleum Association	J. W. Proctor	CPA

The following registered as interveners at the hearing of the Alberta and Southern application:

Interveners	Represented by	Abbreviation of name used in Report
The British American Oil Company Limited	W. M. Winterton	British American
Canadian Delhi Oil Ltd.	S. McKinnon	Canadian Delhi
Canadian Fina Oil Limited	G. W. Brown	Canadian Fina
Canadian Petroleum Association	D. W. MacFarlane	
Great Plains Development Company of Canada, Ltd.	P. Podmaroff	Great Plains
Hudson's Bay Oil and Gas Company Limited	L. B. Bannicke	
Imperial Oil Limited	D. E. Lewis, Q.C.	Imperial
Independent Petroleum Association of Canada	A. H. Ross	IPAC
Pacific Petroleums Ltd.	G. E. Nickoloff	Pacific
Pan American Petroleum Corporation	L. M. Clark	
Shell Canada Limited	C. R. Fetherston	
Socony Mobil Oil of Canada, Ltd.	E. M. Bredin, Q.C.	Socony Mobil
Tenneco Oil & Minerals Ltd.	C. D. Williams, Q.C.	Tenneco
Trans-Canada Pipe Lines Limited	N. J. McNeill, Q.C.	Trans-Canada
Westcoast Transmission Company Limited	D. P. McDonald, Q.C.	Westcoast
Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited	G. H. Steer, Q.C. B. V. Massie, Q.C.	
City of Calgary	S. J. Helman, Q.C.	

Interveners	Represented by	Abbreviation of name used in Report
City of Edmonton	A. F. MacDonald, Q.C.	
City of Lethbridge	T. D. Hetherington	
Sherritt Gordon Mines Limited	C. W. Clement, Q.C. M. Rodney	
Mountain Pacific Pipeline Ltd.	J. B. Ballem	Mountain Pacific
Triad Oil Co. Ltd.	J. R. Lacey	

III SUBMISSION OF TRANS-CANADA PIPE LINES LIMITED

1. Application for New Permit, Increased Volumes in Subsisting Permit and Consolidation of Permits

Trans-Canada's application requested permission to remove from the Province 2.480 trillion cubic feet of gas in addition to the 9.640 trillion cubic feet heretofore authorized. It asked for a new permit for 2.150 trillion cubic feet of gas to be withdrawn from three fields not named in the present permit and an increase of 0.330 trillion cubic feet from fields included in Permit No. TC 64-5.

The applicant further requested that the new permit and Permit No. TC 64-5, as amended, be consolidated into one permit having the following provisions:

(i) that its term commence on the day of its date and end on the 31st day of October, 1989;

(ii) that the quantities of gas that may be removed from the Province pursuant thereto shall not exceed 1,550,000,000 cubic feet of gas in any one day or 525,000,000,000 cubic feet in any consecutive twelve-month period or more than 12,120,000,000,000 cubic feet of gas during the term (the latter quantity being inclusive of the quantities removed under Permits TC 54-1, TC 59-2, TC 60-3, TC 60-4 and TC 64-5).

(iii) that for the purpose only of alleviating temporary operating problems caused by pipe line or equipment failure, the volume of gas that may be removed from the Province in any one day be 110 per cent of the volume of gas that may otherwise be so removed in any one day;

(iv) that all quantities of gas for the purpose of the permit be referred to a 14.65 pounds per square inch absolute pressure base and a 60 degree Fahrenheit temperature base.

An estimate of sales of the Trans-Canada system from 1964 to 1971 and thereafter was presented by V. L. Horte, Vice-President Gas Supply of Trans-Canada, indicating increased market requirements for gas in Eastern Canada. The volumes under permit and those now applied for would meet the estimated increasing total requirements until 1971 and requirements at that level until 1981 when deficiencies would commence. Upon examination Mr. Horte said the applicant is seeking additional markets in the United States and if these materialized the volumes being sought would not meet the estimated 1971 level requirements.

Trans-Canada gave evidence of volumes of gas under contracts, by means of a table listing volumes under contract by fields, by years and, in a separate tabulation showing the volumes, by each of the eight types of gas purchase contracts used by the company. The tables indicated that substantially all of the gas already authorized for removal and that subject to this application is under contract.

2. Reserves and Deliverability

Evidence with respect to reserves of gas was given by B. D. Cochrane of Trans-Canada and with respect to deliverability of gas by A. G. Warke of Trans-Canada. Detailed reserve estimates were presented for Edson, Hespero and Medicine River, the new fields from which Trans-Canada proposes to remove gas, as well as for eleven other fields and areas in which the estimates of Trans-Canada and those published in the most recent Board reserves report(1) varied appreciably.

Basic deliverability data and a detailed deliverability schedule were presented showing how gas would be produced from the Edson, Hespero and Medicine River fields. Summary schedules were also presented indicating the manner in which Trans-Canada's total requirements could be met from fields already under permit and from those now being applied for. The schedules indicated that with requirements, including increased sales in Eastern Canada, projected at the 1971 level until 1989, deficiencies would commence in 1980 and total some two trillion cubic feet by the end of the period.

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(1) OGCB Report 64-8. Reserves of Crude Oil Gas, Natural Gas Liquids and Sulphur. Province of Alberta. December 31, 1963.

3. Alberta Requirements

The applicant presented no evidence with respect to the thirty-year requirements of the Province. In its computation of Alberta's surplus it used the Board's estimate of Alberta's thirty-year requirements presented in OGCB Report 64-1(2) after allowing for moving the thirty-year period forward one year.

4. Trends and Surplus

Trans-Canada presented an analysis of its estimate of the Alberta surplus after meeting Alberta's thirty-year requirements and the present permit commitments. In its study the applicant used a provincial reserve of 37.6 trillion cubic feet as of April, 1964. This figure was obtained by adjusting the Board's reserve estimate of 34.7 trillion cubic feet as of December 31, 1963, to reflect increases in reserves in certain fields which were estimated by Trans-Canada to have resulted largely by development since the end of 1963.

An analysis of trends in exploration and the growth of Alberta gas reserves was made by Trans-Canada using the method shown in OGCB Report 64-8 but revising the data in the light of the increase, estimated by Trans-Canada, in reserves in certain fields. It concluded that the long term growth rate of initial marketable reserves, due both to new discoveries and to appreciation of known reserves, has been 2.6 trillion cubic feet per year. It stated also that, on a fully appreciated basis, the cumulative reserves discovered per wildcat well drilled have remained at about 7.0 billion cubic feet over the last four years. It believed that these long term growth rates will be maintained.

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(2) Report on an application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956. February, 1964.

For the computation of Alberta's surplus as of April, 1964, which Trans-Canada presented, it followed the method used by the Board in OGCB Report 64-1. It used its revised reserve estimate and its trend data for estimating the reserves available from two years of trends. It advanced by one year the Board's most recent estimate of Alberta's thirty-year requirements. Permit commitments were adjusted for intervening removals of gas from the Province. Trans-Canada concluded that Alberta's surplus as of April, 1964, was 7.2 trillion cubic feet or 9.7 trillion cubic feet after release of gas required to protect peak days in permits.

IV SUBMISSION OF ALBERTA AND SOUTHERN GAS CO. LTD.

1. Application for Amendment and Consolidation of Permits

The application of Alberta and Southern requested amendments of the existing Permits No. AS 59-1 and No. AS 60-2 with respect to the Schedule of Fields contained in each permit. Deletion of the Parkland Field which can no longer deliver gas and the addition of nine Fields or Areas in which gas has now been contracted was sought.

The applicant also requested that the permits, each as amended, be consolidated into one permit having the following provisions:

(i) that its term commence on the day of its date and end on the 31st day of October, 1989;

(ii) that the quantities of gas that may be removed from the Province pursuant thereto shall not exceed

(a) for the period commencing on its date and ending on the 31st day of October, 1966, 500,000,000 cubic feet in any one day, or 165,000,000,000 cubic feet in any one year ending on the 31st day of October;

(b) for the period commencing on the 1st day of November, 1966 and ending on the 31st day of October, 1967, 620,000,000 cubic feet in any one day, or 207,000,000,000 cubic feet in that year;

(c) for the period commencing on the 1st day of November, 1967 and ending on the 31st day of October, 1989, 750,000,000 cubic feet in any one day, or 250,000,000,000 cubic feet in any one year ending on the 31st day of October;

(d) for its term, that quantity of gas which when added to the quantity of gas removed under Permit No. AS 59-1 and Permit No. AS 60-2 produces a total of 6,450,000,000,000 cubic feet;

(iii) that, notwithstanding the limitations in the quantities of gas that may be removed from the Province in any one day, for the purpose only of alleviating temporary operating problems caused by pipe line or equipment failure, the volume of gas that may be removed from the Province in any one day be 110 per cent of the volume of gas that may otherwise be so removed in any one day;

(iv) that all quantities of gas for the purpose of the permit be referred to a 14.65 pounds per square inch absolute pressure base and a 60 degree Fahrenheit temperature base.

The granting of the application would increase the volumes permitted for removal by 2.322 trillion cubic feet from the 4.128 trillion cubic feet (4.200 measured at 14.4 pounds per square inch absolute) now authorized. The term of the permit would be extended from October 31, 1986, to October 31, 1989.

Alberta and Southern presented letter agreements between itself and its customers, Pacific Gas Transmission Company and Canadian-Montana Pipe Line Company, covering the sale of the increased quantities of gas for which it is seeking authorization to remove.

When asked by Mr. Massie, the reason for requesting an extension in the term of the permit from 1986 to 1989, Mr. Blair, Vice-President of Alberta and Southern, stated that the applicant is currently contracting for additional gas on a twenty-five year contract basis in fields from which it is now purchasing gas, so that these contracts will extend beyond the term of the present permits. Alberta and Southern sought an extension to provide markets for the remainder of the reserves in these fields.

Data presented by Alberta and Southern in support of its application, as amended by evidence of its witness with respect to supply reserves and supply deliverability, A. N. Boyse, indicated that some 90 per cent of the reserves in the fields contained in its existing permits plus the new fields applied for, are under contract or option to the applicant. Substantially all of the daily quantities of gas requested were either under contract, under option or under active contract negotiation.

2. Reserves and Deliverability

A. N. Boyse of Alberta and Southern presented evidence on reserves and deliverability. Detailed reserve estimates were given for six new fields or pools which the applicant wished included in the permit applied for. In addition detailed estimates were presented for six fields or areas contained in its present permits and for which the reserve estimates of Alberta and Southern differ substantially from the applicant's estimates of reserves presented to the Board in support of its application for a permit in September, 1959.

The applicant presented a detailed illustrative deliverability schedule showing how the volumes of gas applied for could be delivered by the fields named in the subsisting permits and those to be named in the permit applied for. The schedule indicated peak day deficiencies commencing in 1986 and annual deficiencies totalling a relatively minor amount of 245 billion cubic feet.

3. Alberta Requirements

The applicant did not present evidence with respect to Alberta's requirements. In its illustrative analysis of supply, requirements and surplus gas in Alberta, it used the data presented in OGCB Report 64-1.

4. Trends and Surplus

A study of the trends in the growth of gas reserves in Western Alberta (west of the Fifth Meridian and south of Township 80) was made by Alberta and Southern and presented by S. R. Blair and G. M. Chernoff. From the study, they concluded:

(1) Exploratory drilling in that area is increasing and becoming a larger portion of drilling in the whole Province.

(2) Results of exploratory activity in the designated area are superior to those for the Province as a whole.

(3) There is a correlation between increase in gas reserves in the area and market incentive for gas. The rate of increase during the period 1958 to 1960 inclusive, when gas purchase contracts were being offered by permittees, was over double the rates attained prior to and since that time.

Mr. Blair, in noting that the study did not cover the Province as a whole, submitted that the conclusions never the less were germane to the overall consideration.

An illustrative analysis of supply, requirements and surplus of gas in Alberta was prepared by the applicant. It followed the method presented in OGCB Report 64-1, but subdivided total quantities of gas into those which are "presently contractable" and those which are "contractable in future". Included in the latter category is 4.5 trillion cubic feet which it was estimated would be available from five years of trends. This is the minimum amount which, on the basis of trends since 1948, Alberta and Southern concluded will become established in any five-year period in the future. Mr. Blair stated that this figure represented a "rock bottom minimum" of future reserves that the Board could use and did not represent "a forecast of the most likely figure that will occur within five years".

After making allowance for the requirements of the present applications of Trans-Canada and Alberta and Southern, the applicant concluded that there would be a surplus of "presently contractable" gas in the amount of 3.7 trillion cubic feet and a surplus of "future contractable" gas in the amount of 1.7 trillion cubic feet, for a total surplus of 5.4 trillion cubic feet.

V SUBMISSIONS OF INTERVENERS

1. Alberta and Southern Gas Co. Ltd.

Alberta and Southern registered as an intervener at the hearing of Trans-Canada's application. Counsel for Alberta and Southern did not lead evidence, but examined witnesses of the applicant and other interveners and presented argument.

2. Trans-Canada Pipe Lines Limited

Trans-Canada registered as an intervener at the hearing of the Alberta and Southern application for the purpose of examining witnesses of the applicant and other interveners and presenting argument.

3. Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited

Canadian Western Natural Gas Company Limited and Northwestern Utilities, Limited intervened at both hearings. Evidence was lead through B. F. Willson, President; J. D. Maybin, Vice-President and B. W. Snyder.

The Utilities Companies opposed the granting of the applications of Trans-Canada and Alberta and Southern at this time. They stated that they had never been opposed to the removal of gas from the Province, if the interests of the Alberta consumer were fully protected for a reasonable period of time. They contended, however, on the basis of their own detailed analysis, which is reviewed in Appendix C, that the full requirements of Alberta gas consumers for the thirty-year period from 1964 to 1993 inclusive, will be 17.8 trillion cubic feet. They contended further that there are insufficient reserves to protect this requirement and to protect adequately the permit requirements.

The Utilities Companies maintained that the full thirty-year annual and peak day requirements of the Province should be provided for "on the basis of established and economically available reserves". They stated that the concept of issuing a permit authorizing removal of gas from fields where there are insufficient reserves to sustain the initial permit volumes, in terms of daily deliveries, throughout the life of the permit was unsound. They summarized their position at the hearing of the Trans-Canada application as follows:

".....we submit that the application of Trans-Canada Pipe Lines should be refused until such time as the proven reserves of the province are of sufficient magnitude to:

(i) take care of the full 30-year provincial requirements (including sufficient cushion gas to ensure full deliverability in the 30th year)

(ii) take care of the full requirements of the existing permits including gas for deliverability purposes throughout the entire permit period.

(iii) take care of the volumes required to fully satisfy new applications."

At the hearing of the Alberta and Southern application, their summary of their position was as follows:

> ".....Canadian Western and Northwestern oppose granting of the application of Alberta and Southern Gas Co. Ltd. until such time as the protection for the consumers within the Province has been restored to a full thirty-year level for both annual and peak day supply on the basis of established and economically available reserves."

Furthermore, in answer to a question by Mr. MacKimmie as to how much reserves the producers must find before the Utilities Companies would remove their objections, Mr. Willson stated:

> ".....we feel, as we mentioned, the full thirty-year needs of the Province should be protected. The degree of protection given the export companies is another matter and we would leave that to the judgment of the Board."

However, Mr. Snyder in answer to a question by the Board in this matter, stated:

> "We are aware that the present Trans-Canada permit, in the granting of that permit, the availability of gas to meet the terminal year deliverabilities was waived, and at this point this gives us some concern, and it is our position that quantities to meet those terminal year requirements should be in sight before additional permits are granted, in order to prevent a situation of possible conflict of interest down the road."

The Utilities Companies stated that the former thirty-year gas supply protection afforded Alberta consumers has been progressively eroded by recent decisions of the Board on permit applications. This referred to the Board's use of two years of trend gas plus a part of the gas at the time considered to be beyond economic reach when considering reserves available for requirements within and beyond the Province. The Utilities Companies said that unsound reliance has been placed on these reserves in view of "the unfavorable trend in the rate of discovery of new reserves". These interveners presented a graph indicating that, despite the maintenance of a high level of wildcat well drilling, the rate of growth of reserves has declined in the early 1960's compared to the 1950's.

In discussing the propriety of using trend gas in the calculation of Alberta surplus, witnesses for the Utilities Companies recognized the provisions of section 8 of The Gas Resources Preservation Act, 1956 (1) but maintained their position that in using trends in the growth of reserves, consideration should also be given to growth in markets. The interveners' submission at the hearing of the Trans-Canada application stated:

> "The requirements of Alberta consumers which have been considered in all proceedings to date have not been ultimate requirements but have been those of a rolling thirty-year period which, for many years, will be expected to show a progressive increase in each successive period that may be examined. It must also be kept in mind that present export permits are fundamentally based on the current level of export

---

(1) Section 8, subsection (3) reads as follows:

> "(3) The Board shall not grant a permit for the removal of any gas or propane from the Province unless in its opinion it is in the public interest to do so having regard to
> (a) the present and future needs of persons within the Province, and
> (b) the established reserves and the trends in growth and discovery of reserves of gas or propane in the Province."

> market development except perhaps for a few additional years of growth. There is every reason to expect very substantial growth in export market areas. If reserves come within economic reach by reason of pipe line extensions or if discoveries now anticipated do materialize, they should be taken into account at that time in terms of both the export and local market situations as they are appraised at that same time."

In reply to questioning by the Board, Mr. Willson stated:

> ".....the forecast growth of the export market is such that this analysis will demonstrate that it is risky for the protection of the Alberta consumer to allocate to his needs assumed future discoveries."

Mr. Willson went on to say that he believed that under the Board's general responsibility with respect to protecting the public interest, set out in section 8 of the Act, that the Board is responsible for considering growth of markets outside the Province. In elaboration of their views the Utilities Companies prepared Figure 3 of Exhibit No. 22 filed at the hearing of the application of Alberta and Southern. This figure showed the difference between remaining marketable reserves and the total projected requirements of presently connected markets. The requirements included full projected growth over the periods of the permits plus reserves to meet peak day requirements in the terminal years of the permits. On this basis, the figure indicated a requirement in excess of established reserves of some 27 trillion cubic feet. Furthermore, the figure indicated that the rate of growth of the connected markets greatly exceeds the current rate of growth of remaining marketable reserves. In commenting, the Utilities Companies stated:

> ".....We submit that the Board should not count on and utilize the so-called "trend" gas except to the extent that the rate of discovery over a reasonable period exceeds the rate of increase in anticipated market requirements."

and in reply to a question by Mr. McNeill:

> ".....what figure 3 tends to illustrate is that the presently connected markets provincially for thirty years and export for twenty-five, assuming certain rates of growth, as set out in the text, will require some 60 trillion cubic feet to satisfy at the present time. We are not saying that that all has to be on hand at the present time, but we are saying that this is what this Board is faced with in analysing whether or not it is sound for Alberta to permit the export of additional gas at the present time....."

In rebuttal to the Utilities Companies evidence concerning a declining rate of reserves growth, Trans-Canada presented data indicating that for any particular reserve estimate there appeared to be a declining discovery rate due to lack of appreciation of newly discovered reserves. The data demonstrated that for the period from 1949 to April, 1964, a gas discovery rate of six billion cubic feet per wildcat well was maintained. Trans-Canada stated that on a fully appreciated basis, one can expect a discovery rate of approximately seven billion cubic feet per wildcat well.

With respect to the use of reserves presently considered beyond economic reach, Trans-Canada made an analysis of all fields which the Board placed in that category. The fields were examined with respect to geology, present reserves, potential development and distance from present and probable new pipe lines. It concluded that of the 3,641 billion cubic feet shown in OGCB Report 64-8 as beyond economic reach as of December 31, 1963, 1,653 billion cubic feet can be classified as now within economic reach and 743 billion cubic feet as reserves expected to be within economic reach in the near future. It stated that on this basis the Board should find a minimum of two-thirds of these reserves to be within economic reach when calculating Alberta's surplus.

Denial of the application, in the view of the Utilities Companies, would aid in counteracting the upward pressure on the cost of gas for local consumers, resulting in a more favourable climate for the establishment of industry, and would help stimulate the provincial economy by necessitating more active exploration efforts. This thesis was attacked by several of the producing companies appearing as interveners, by the Canadian Petroleum Association and by the Independent Petroleum Association of Canada, all of whom maintained that the denial of the applications would result in a decline in drilling activity and act as a depressant on the provincial economy.

4. City of Calgary

The City of Calgary presented evidence at the Trans-Canada hearing through its witness, Mayor G. MacEwan, and at the Alberta and Southern hearing through its witness, S. J. Davies. At the Trans-Canada hearing, a unanimous resolution of the Calgary City Council supporting the intervention of the Utilities Companies was presented. Mayor MacEwan said that the Council acted on the recommendation of its Gas Committee which studied the Utilities Companies submission and endorsed it, but which had not seen the Trans-Canada application. He said the City's position was that it is not opposing removal of gas from the Province but felt that it should be preceded by proper precautions with respect to supply, price and accessibility.

During the Alberta and Southern hearing, Mr. Davies stated that the City of Calgary was in favour of the removal of gas from the Province if the following conditions were embodied in any permit granted to Alberta and Southern:

(1) The applicant must supply to Canadian Western Natural Gas Company Limited, in priority to any gas removed from the Province, any gas which gas consumers in Calgary may require during the lifetime of the permit.

(2) The price to be paid to Alberta and Southern by Canadian Western Natural Gas Company Limited shall be the lowest price being paid by the applicant for gas under its gas purchase contracts.

(3) The present condition of calculating transportation

cost from the nearest point of supply shall be continued.

In elaboration Mr. Davies stated that the City desired amendment of the clauses in the permits dealing with the obligation of permittees to supply gas "at a reasonable price to any community or consumer within the Province" to include "public utility", as they had some doubt as to whether a public utility is either a community or consumer. It wished the wording "can reasonably be so supplied by the Permittee" to be replaced by the words "in priority to any gas exported by it". During examination, Mr. Davies made it clear that he felt the provisions requested should apply to permits which may be granted to either Trans-Canada or Alberta and Southern and should apply to gas required by any consumers in the Province.

In rebuttal, Mr. Blair stated that the first and second of the proposed conditions set out above were not acceptable to Alberta and Southern and would create insurmountable difficulties in other jurisdictions and cause financial and business difficulties.

In his closing statement, Mr. McNeill, on behalf of Trans-Canada, stated that "it could not get by with conditions suggested by the City of Calgary without the safeguarding of an arbitrator who would settle any dispute or clarification required in connection with either supply or price. We would suggest, sir, that this Board and the Public Utilities Board, as presently named, must be retained in those conditions."

5. City of Edmonton

The City of Edmonton intervened at both hearings and presented evidence at the Trans-Canada hearing through its witness, City Commissioner D. B. Menzies and at the Alberta and Southern hearing through Mayor W. Hawrelak.

The City of Edmonton at the first hearing supported the position of the Utilities Companies in requesting that the Trans-Canada application be denied. It stated that it believed "that future needs of persons within the Province can only be protected if the thirty-year needs of Albertans get first priority from established and economic reserves of gas".

In reply to the questions, Mr. Menzies stated that the City was concerned both with supply and price of gas in the Edmonton area but that the City had not made any studies itself of the possible effect on these by the granting of the Trans-Canada application.

In opposing the granting of the Alberta and Southern application the City stated that:

(1) Low price fuel is of primary importance to the manufacturing industry, two-thirds of which is concentrated in the Edmonton area.

(2) If industrial expansion continues, fuel requirements may exceed those provided for in Board estimates.

(3) Permittees have received preferential treatment over Alberta consumers in that permit requirements are from established reserves whereas the 30-year Alberta requirements are

from established reserves, reserves yet to be discovered and reserves presently beyond economic reach.

(4) The removal from the Province of large quantities of gas has resulted in an upward trend in gas prices.

(5) Applications should be denied until such time as full protection for the 30-year provincial requirements is assured from proven gas reserves within economic reach.

(6) The Board should allocate gas in specific fields sufficient to ensure Edmonton area needs for the next thirty years to absolve it from direct competition for its gas supply with companies removing gas from the Province.

Mayor Hawrelak stated that it was his purpose "to tell the Board that they must be ultra-conservative in making certain that we have adequate supplies of gas and that they must be very optimistic as to what might be required by both Alberta and the exporting companies of gas from Alberta".

The mayor further stated that the City believed that there should be a price differential between the price of gas for an extraprovincial market and gas for local use. He said "I think that natural gas to the people of Alberta is a sort of heritage......, and the people of Alberta ought to have the best possible use of that heritage for themselves and for posterity." He said further ".....we believe that in Alberta we have a certain advantage in the low cost of fuel and we want to make certain nothing happens to that advantage in the years to come." In answer to a question by Mr. MacKimmie, he stated "It is for their (the producers) own interests for future development that there should be a price differential for local consumption in Alberta with regard to that gas which is sold on the export market."

6. City of Lethbridge

The City of Lethbridge was represented during part of the Alberta and Southern hearing but did not present a submission.

7. Sherritt Gordon Mines Limited

Sherritt Gordon, a major consumer of gas at Fort Saskatchewan, intervened at both hearings. Evidence was presented at the hearing of the Trans-Canada application by Mr. W. H. Young, Vice-President and Manager, and at the hearing of the Alberta and Southern application by Mr. J. Ferguson, Superintendent of Administration.

Sherritt Gordon outlined the background of events leading to its establishment in Alberta in 1952 principally because of the availability of low priced gas and the economic problems it faced with respect to the effect of rising gas prices on its operations.

The submission presented by Mr. Young stated that Sherritt Gordon opposed the granting of the Trans-Canada application because of the effect it believed this would have on the price of gas in Alberta, and on cross-examination he also dwelt upon the intervener's need of an assured supply of gas over the years. At the later hearing, Mr. Ferguson stated, upon examination, "I would say that we are not against export as such, as long as there are sufficient reserves available for the use of, not only people such as ourselves, but all industry and consumers in Alberta, this is why we came to the Province, being assured that there would be, and that the price will not be too unduly affected by those exports."

8. Canadian Petroleum Association

The interventions of the Alberta Division of the Canadian Petroleum Association were presented by Mr. S. Stewart, Chairman, Alberta Board of Directors. He was assisted at the Trans-Canada hearing by G. Connell and at the Alberta and Southern hearing by G. Connell, Z. Polrupa and O. Erdman.

(1) Reserves

CPA discussed the Lahee method of reserve estimation employed by it. Due to the rigid standards of the method, it maintained that a very conservative estimate resulted from its use and substantial appreciation of reserves in future years can be expected. It believed that if the Board reserve estimates (which is somewhat similar to the Lahee method and resulted in a reserve estimate of 32.9 trillion cubic feet as at December 31, 1963, compared to the estimate of 29.9 trillion cubic feet by CPA) were examined on the same basis, the same conclusion would hold, that the estimate was conservative and will always be subject to appreciation.

The Canadian Petroleum Association expressed the opinion that the Board's 1964 estimate of ultimate marketable reserves of 60 to 80 trillion cubic feet was very conservative. It estimated the ultimate reserve to be in the range of about 90 to 150 trillion cubic feet. It concluded that the attainment of these potential reserves was more a matter of providing exploration incentive than a matter for speculation as to whether the gas is contained in the sediments.

(2) Use of Trends

CPA stated that the whole controversy over the thirty-year provincial protection really revolved around the question of whether or not trend gas should be included and whether or not established reserves should include some "probable estimates". It was CPA's opinion that discovery trends can be projected well beyond the two years considered by the Board. In elaboration, Mr. Connell stated that CPA agreed with the Board's use of fifty per cent(2) of probable reserves in arriving at established reserves and felt that the Board should use five to ten years of trend gas in its calculations of reserves available to meet provincial and extraprovincial requirements.

(3) Economics of Gas Exploration and Production

CPA presented the results of a study made by a member company to analyse the effect of delay in gas sales on the economics of exploration and production. In the study a model gas field having the approximate characteristics of an actual foothills field was used. Three cases were considered with gas sales commencing 3, 13 and 28 years after discovery of the field. The discounted rate of return on investment for the cases was 10 per cent, 6 per cent and 3½ per cent, respectively. The study showed that only when the sale gas commenced within thirteen years of discovery was there a rate of return higher than the cost of capital.

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(2) Mr. Connell said "fifty per cent." The Board uses a proportion which is usually, but not invariably, fifty per cent.

(4) Relationship of Oil and Gas Industry to Alberta Economy

Canadian Petroleum Association took issue with the Utilities Companies submission that "in order to attract Industry to Alberta and to broaden the base of the provincial economy, it is essential that prospective new industries be offered low cost energy supplies at stable and predictable prices." It believed that fuel costs are not a key factor in determining an industrial location. For Alberta to develop a diversified industrial base, it believed, there must be a sizeable local market. Until population growth occurs it will be necessary to concentrate on those industries which have a natural advantage in Alberta. Oil and gas production is such an industry and should be fostered rather than subjected to hindrances such as a deferment of marketing opportunities.

CPA gave evidence of the contribution of the oil and gas industry over the period, 1947 to 1963, to the provincial treasury through sales, bonuses, fees, rentals, royalties and mineral taxes. It also indicated its contribution to the economic life of the Province through industry expenditures.

9. Independent Petroleum Association of Canada

A. H. Ross presented a brief on behalf of the Independent Petroleum Association of Canada at the Alberta and Southern hearing.

IPAC supported the application of Alberta and Southern, subject to the qualification that the Board, using its present practices, determines that there is a sufficient supply of gas surplus to provincial needs.

In regard to the Board's present practice, IPAC expressed the following opinions:

(1) The Board has been conservative in determining past estimates of gas reserves.

(2) There is sufficient justification to assume that a portion of gas now classified as beyond economic reach will be within economic reach within the next 30 years, and in fact 45 per cent of gas reserves considered beyond economic reach in the Board's June 30, 1953, report were connected to market by September, 1963.

(3) The use of growth trends in estimating future reserves is justified in the light of past experience. The present Board policy of using two years of growth in reserves is very conservative. In enlargement, Mr. Ross stated that IPAC would consider some period between two and five years

in length to be reasonable.

(4) The Board's prediction of future provincial requirements in the past has proven to be high in comparison to actual consumption and IPAC believes these predictions provide adequate protection of supply to Alberta consumers.

(5) The deferment of gas markets will discourage producers in both the exploration for and development of gas prospects.

(6) Removal of gas from Alberta has been and will continue to be most beneficial to Albertans, considering expansion of job opportunities, government revenues and the bringing of gas to new communities which could not otherwise be economically supplied.

10. Westcoast Transmission Company Limited

Westcoast was represented at the Alberta and Southern hearing, but restricted its participation in the proceedings to cross-examination.

11. Mountain Pacific Pipeline Ltd.

Mountain Pacific was represented at the Alberta and Southern hearing but made no submission.

12. Hudson's Bay Oil and Gas Company Limited

Hudson's Bay Oil and Gas Company Limited intervened at both hearings. In each case it supported the applicant.

With regard to reserves, Hudson's Bay said the Board's published estimates for developed fields in which it was interested were reasonably close to its own. The Edson field, however, being recently developed, held greater reserves than the Board's estimates showed. At the Trans-Canada hearing, at which the Edson reserves were directly involved, Hudson's Bay presented its reserve study for this field.

Hudson's Bay said that it had increased its gas reserves in the Province by thirty per cent since the first of 1961. It gave evidence of the wells it had drilled and the money it had spent in exploration for gas during this period. Upon cross-examination, D. C. Jones, Vice-President of Hudson's Bay, gave as a reason for the large exploratory effort in the last two years, the indications in May, 1962, that Trans-Canada was interested in purchasing additional gas and later conversations with Trans-Canada to that end. Hudson's Bay submitted that continuing incentive in the form of new and expanding markets was necessary to warrant large expenditures on gas exploration and Mr. Jones stated that if Trans-Canada's application were to be deferred, Hudson's Bay's efforts of this nature would slow down. He also said that some delay between the finding of gas and its sale was normal and resulted in modest returns on invested capital. Additional delays resulting from denial of permits would impair the capital-raising ability of those engaged in gas exploration.

Mr. Jones expressed the opinion that the revenues and industry activity resulting from the removal of gas from the

Province would far outweigh , from the point of view of provincial benefit, disadvantages which may result from nominal increases in local gas costs.

Commenting on the Board's practice of using two years of trend gas in calculation of provincial reserves, Mr. Jones said the practice was a proper one.

13. Pan American Petroleum Corporation

Pan American Petroleum Corporation supported the applicant at each of the hearings.

The Pan American submissions contained reserve studies of three fields in which it is interested, Bigstone, Pine North-west and Marten Hills. Its evidence indicated that these studies were presented because for each field the Pan American estimate was substantially greater than the last published Board estimate and because the fields are now within economic reach. Speaking of the Board's reserve estimates generally, A. H. Denny, Pan American's Division Gas Sales Superintendnent, said they were conservative, and this, he said, occurred because the Board would not have as recent data as the operator and the Board did not use seismic information.

In discussing the use of trend gas in calculating reserves, Mr. Denny stated the gas industry in Alberta had so matured that a period longer than two years could be used, and he thought five to ten years would be reasonable.

14. Shell Canada Limited

Shell Canada Limited was represented at both hearings. At the Trans-Canada hearing, its participation was limited to cross-examination, but at the Alberta and Southern hearing it also presented a submission supporting the application.

In the part of the Shell submission dealing with the volume of reserves, reserve studies were presented of certain fields in which Shell was interested and for which it had information not then of public record. The information was based on confidential seismic records and data obtained at recently drilled wells. The pools studied were in the Burnt Timber, Crossfield, Harmattan East, Jumping Pound, Jumping Pound West, Sarcee and Waterton fields.

Shell submitted that there was a present surplus of gas reserves over the provincial requirements, existing permit commitments and the additional volumes requested in the subject applications. In calculating established reserves the trend of future discoveries in the next five years should be considered. Reserves are found as a result of exploration work that commenced, on the average, seven or eight years before. J. F. Redmond, Vice-President and a director of Shell, stated that with such long range programs there was no reason to think that the five-year trend figure would not be realized. Its use would be realistic and anything less conservative. With regard to provincial requirements Shell questioned the size of the industrial requirements for which the Utilities Companies would make allowances.

Shell also submitted that the granting of the applications would be in the public interest of the Province. It would ensure substantial royalties, increased capital investment and employment in the Province and additional provincial revenues from lease sales. Conversely, denial of the applications would reduce the incentive to explore for gas and adversely affect revenues and employment opportunities. Shell claimed that a healthy oil and gas industry was more important to Alberta than industries which might be attracted by inexpensive fuel, but which so far had not been inclined to establish in the Province.

While Shell recognized that it was the established policy that Alberta consumers be protected as to reserves and price, it pointed out that this protection found in Alberta was unique. It suggested that the cost of holding back an inordinate or large reserve shouldn't be borne entirely by the producer, but rather by those who receive this protection. The best safeguard against unreasonable increases in the price of gas in Alberta would be the discovery of significant new reserves, and this depended on an intensive exploration effort and on real incentives to find and produce gas.

As income from gas sales was used in part by the producer in the exploration for oil, gas and sulphur, curtailment or deferment of income would reduce the exploration effort. It would also reduce the producers' opportunity to obtain a reasonable rate of return on their investment. A deferment of even a year or two would result in the holding back of expenditures that could be held back. Refusal to accept the markets available would involve a risk of losing them.

15. Triad Oil Co. Ltd.

At each hearing Triad Oil Co. Ltd. appeared and supported the application. It has substantial holdings in the Edson field mentioned in the Trans-Canada application.

Triad submitted that the granting of the applications was necessary to provide incentive for further gas exploration. Its witness, J. R. Lacey, said at the Trans-Canada hearing that during the last two or three years 70 per cent of its expenditures on exploration were gas-directed. He said Triad's policy was to invest in exploration for the purposes of near term revenue, and that if the application was denied the intervener would "move right out of the gas exploration business."

16. Canadian Pacific Oil and Gas Limited

Canadian Pacific intervened in support of the applicant at the Trans-Canada hearing. It stated that it expected to expend during 1964 approximately $5,200,000 in gas-bearing areas as compared with $2,100,000 in 1963. However its witness, J. F. Frey, said that denial of the application would result in reduction of its investments in the exploration and development of gas in Alberta.

The submission included a reserve study of the Rolling Hills area.

17. Canadian Industrial Gas Limited

Canadian Industrial appeared at the Trans-Canada hearing for the purposes of cross-examination and argument.

In its argument it said that although engaged in the supply of gas to industrial consumers in the Edmonton area, it did not oppose the application. It took issue with a suggestion it attributed to the Utilities Companies that there should not be competition for the industrial gas consumer, and said the way to insure that industries will receive relatively low cost gas was to have competition.

18. Hamilton Brothers Canadian Gas Company Ltd.

Hamilton Brothers intervened at the Trans-Canada hearing. As an interest owner in the Edson field it supported the application. Its witness, R. Emerson, said that if the application were denied Hamilton Brothers would stop exploration for gas, and the revenues it anticipates from the Edson field would be lost to it.

When asked on cross-examination to comment on the Utilities Companies' assertion that denial of the application would create an incentive to operators to find more gas, Mr. Emerson told of a reserve of gas which Hamilton Brothers and another operator had discovered in close proximity to a gathering system of Northwestern Utilities, Limited. They were unable to sell the gas to that utility on an economically feasible basis.

19. Royalite Oil Company, Limited

Royalite intervened upon the Trans-Canada application and urged favourable consideration of it. It represented that it was a working interest owner in the Edson field and a substantial producer of gas in the Province. It said approval of the application would create additional incentive for the exploration for and development of additional gas reserves.

20. The Alberta Gas Trunk Line Company Limited

Trunk Line was represented at the Trans-Canada hearing but did not actively participate in the proceedings.

21. Uno-Tex Petroleum Corporation

Uno-Tex intervened only at the Trans-Canada hearing. It supported the submission of Hudson's Bay and thus supported the applicant. Uno-Tex, since July 30, 1963, had expended over $3,000,000 in the Edson area on leases, reservations, roads and drilling. It said it would not have been so active in the area without the incentive of an early gas market.

22. The British American Oil Company Limited

British American intervened on the Alberta and Southern application to request that the application be approved.

British American gave its estimate of marketable reserves of gas in Alberta remaining at the end of 1963, and said this estimate was in general agreement with the Board's estimates but changed in the light of development activity and reservoir evaluations available since the year end. In addition British American estimated the ultimate marketable gas reserves of the Province as in the order of 150 trillion cubic feet.

British American's comments on trends in reserves growth were based on a study of reserves discovered in the five-year period from 1958 to 1962. Discoveries of 1963 were not considered as there was insufficient time for their development and appreciation. British American concluded that returns for 1961 and 1962 were fairly constant at 550,000 cubic feet for each foot of exploratory drilling, but admitted that this figure projected over a long term would decline. It expected that, if present incentives continue, exploratory drilling will increase over the next five years. It looked for an average annual increase in reserves during this period of about 2.5 trillion cubic feet.

Concerning the use of trends in calculating established reserves, British American suggested that at least five years of trend gas should be considered. It was as reasonable to use trends in establishing supplies of gas as to use trends in establishing future requirements. Such use of trends is necessary to maintain the incentive to find and develop gas reserves.

British American said the success and continued growth of the oil and gas industry would contribute incentives for the location of other industries in Alberta. It intended to continue aggressive exploration for hydrocarbons if adequate incentives were forthcoming for the risk capital required. If production of established reserves should be held back, it would make the exploration development an uneconomic venture. Denial of the application would cause a reduction in exploratory and development effort and a reduction in provincial revenues from lease sales and royalties, and would have an unfavourable effect on the provincial economy.

23. Canadian Delhi Oil Ltd.

At the Alberta and Southern hearing, Canadian Delhi presented a submission as operator of Minnehik-Buck Lake Gas Unit No. 1. It supported the application. The submission contained a study showing reserves in the Minnehik-Buck Lake area in excess of present contract obligations. Alberta and Southern provided the only existing market.

24. Canadian Fina Oil Limited

Canadian Fina presented a submission supporting the Alberta and Southern application.

Canadian Fina referred to the surplus indicated in the Board's February report(3) and stated its opinion that, with additional reserves discovered and developed since September 30, 1963, there was sufficient surplus to justify increasing the applicant's total quantity under permit. The submission commented on Alberta and Southern's reserve estimates for the Pine North-west and Grizzly fields.

Commenting on the effect the decision on the application would have, Canadian Fina said that, if the present shut in reserves were not marketed, exploration and producing companies would have no incentive to explore and would face the prospect of increasing idle investment. On the other hand, permitting removal of the surplus would encourage the discovery and development of gas reserves which would further assure supplies for local needs.

Canadian Fina stated that when permittees were not contracting for gas for extraprovincial markets, the markets were limited and the price to producers eroded to a "distress" level. Commenting on the effect a price increase would have on local consumers, Canadian Fina said that the price paid to producers represented only 15 to 20 per cent of the price to domestic consumers in Alberta. A healthy gas industry would benefit the Province through additional royalties and land bonuses and through increased employment and payments for goods and services.

Canadian Fina took issue with the submissions of the

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(3) OGCB Report 64-1. Report on an Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956.

Utilities Companies, and stated that the measures advocated by them would not stimulate exploration effort, but rather lead to a depression of the gas exploration effort. Upon cross-examination, J. E. Baugh, this intervener's witness, said Canadian Fina regarded the Utilities Companies estimates of possible growth in the requirements of local gas consumers to be exaggerated.

25. Great Plains Development Company of Canada, Ltd.

Great Plains supported the application of Alberta and Southern. It stated that there need be no real concern about adequate gas supplies for Alberta, as local consumers have prior claim to gas produced in the Province. The submission said that to forestall the removal of gas to keep the price down would be a detriment to the people of the Province as it would cause loss of provincial revenue, investment and job opportunities. Also Great Plains submitted that the incentive to find and develop gas is the ability to sell it, and a denial or lengthy delay of markets would slow down exploration.

26. Imperial Oil Limited

At the Alberta and Southern hearing, Imperial presented a study of the reserves in the Benjamin Creek (Waiporous Creek) field. Its witness, H. S. Simpson, stated that Imperial's current estimates of proved and proved plus probable reserves in pools discovered before December 31, 1963, were 30.5 trillion cubic feet and 38 trillion cubic feet.

27. Pacific Petroleums Ltd.

At the Alberta and Southern hearing, Pacific, as operator of the Kaybob Notikewin Unit No. 1 and as working interest owner of additional gas reserves in the Kaybob area, presented a study of gas reserves in the Kaybob and Kaybob East areas.

28. Socony Mobil Oil of Canada, Ltd.

Socony Mobil, as a major interest owner in the Carson Creek Field and the Carson Creek North Field, supported the application of Alberta and Southern. It said that granting of the application would eliminate the necessity of compressing gas from the Carson Creek North Field for storage in the Carson Creek Field and eliminate the possibility that such gas may exceed the storage capacity. Some data regarding the Carson Creek Field were supplied with the submission.

29. Tenneco Oil & Minerals, Ltd.

Tenneco, acting as agent for Tenneco Oil Company, supported the application of Alberta and Southern and stated that if the application were denied its principal would need to reconsider its policy of active exploration for gas reserves, but would look for gas if it could see where it would start selling relatively soon.

Tenneco referred to Tenneco Oil Company's interest in the Crossfield Elkton Unit and supported the submission of the unit operator, Shell Canada Limited. It said this reservoir was underproduced in relation to reserves committed to contract.

Tenneco supported the concept of trend reserves as predicted by the Board and said it provided an incentive to explore and develop additional gas reserves. As between a two-year and a five-year period of trends, its witness, R. H. Byers, leaned toward the five-year period.

VI FINDINGS

The Board having heard publicly the applications under The Gas Resources Preservation Act, 1956, of Trans-Canada Pipe Lines Limited and Alberta and Southern Gas Co. Ltd., and having studied the evidence submitted by the applicants and the interveners at the public hearings, and having regard to the advice of its staff, to its own knowledge, and to its responsibility under the Act, finds as follows:

1. IN THE MATTER OF THE ESTABLISHED RESERVES OF GAS IN THE PROVINCE OF ALBERTA

The Board estimates the established reserves of marketable gas in the Province of Alberta, as of June 30, 1964, to be 35.7 trillion cubic feet (equivalent to 37.6 trillion cubic feet of 1000 Btu gas). Of this total, some 3.4 trillion cubic feet (equivalent to 3.8 trillion cubic feet of 1000 Btu gas) represent reserves presently considered to be beyond economic reach. The current estimate represents an increase of some 2.8 trillion cubic feet since December 31, 1963.

Details of the Board's estimate are presented in Appendix A.

2. IN THE MATTER OF THE TRENDS IN EXPLORATION AND THE GROWTH OF RESERVES OF GAS IN ALBERTA

To June 30, 1964, the cumulative average growth in initial marketable reserves of gas due to new discoveries and to appreciation of previous discoveries has been at a long term rate of some 2.5 trillion cubic feet per year. Over the past two years the annual rate has been very slightly in excess of the long term rate, being 2.6 trillion cubic feet. The Board is confident that the Province may reasonably count upon additional reserves in the amount of 5.0 trillion cubic feet - equivalent to those that would be developed in a two year period at the long term growth rate.

3. IN THE MATTER OF THE PRESENT AND FUTURE REQUIREMENTS OF ALBERTA FOR GAS AND THE PRESENT PERMIT COMMITMENTS

The Board estimates the requirements of Alberta for 1000 Btu gas for the thirty-year period, July 1, 1964, to June 30, 1994, to be some 10.3 trillion cubic feet with a peak day requirement in the thirtieth year of about 2.5 billion cubic feet. For comparison, the Board's estimate presented in its report of February, 1964, to the Lieutenant Governor in Council, indicated the requirements for a thirty-year period commencing October 1, 1963, to be 8.74 trillion cubic feet with a terminal year peak day of 2.3 billion cubic feet. The earlier estimate was prepared on the basis of evidence presented at hearings during and prior to 1959, while the present estimate takes account of evidence submitted in the 1964 hearings. Further, the present estimate includes 0.6 trillion cubic feet of gas as fuel for The Alberta Gas Trunk Line Company Limited system and for process shrinkage at the Empress plant. This volume was previously considered as part of the permit commitments.

The remaining commitments as of June 30, 1964, associated with permits issued for the removal of gas from Alberta total some 15.6 trillion cubic feet of 1000 Btu gas.

A discussion of the Board's study concerning the future requirements of Alberta and details of the remaining permit commitments are presented in Appendix C.

4. IN THE MATTER OF THE MEETING OF THE 1964 TO 1994 REQUIREMENTS OF ALBERTA TOGETHER WITH THE PRESENT PERMIT COMMITMENTS AND THE RESULTING SURPLUS

The Board estimates that reserves totalling some 16.1 trillion cubic feet of 1000 Btu gas are necessary to meet the annual and peak day requirements of Alberta for the thirty-year period commencing July 1, 1964. In addition, the Board estimates that some 18.7 trillion cubic feet of 1000 Btu gas are required to meet the present permit commitments. Of the latter, some 3.1 trillion cubic feet are that gas which is estimated to be necessary to protect the maximum daily delivery rates authorized and anticipated under the permits.

The Board estimates the reserves of gas available to meet the thirty-year requirements of the Province and the remaining permit commitments to be 40.4 trillion cubic feet. This figure includes 1.8 trillion cubic feet of the established reserves now considered beyond economic reach but which the Board is confident will become within economic reach during the thirty-year period. Based on its studies and on the history of the past three or so years during which time some 300 billion cubic feet of the established reserves considered to be beyond economic reach have in fact been or can now be connected to market, the Board does not consider the use of this gas to meet a portion of Alberta's future requirements to in any way affect the long term protection afforded Alberta's consumers.

In addition, the reserves of 40.4 trillion cubic feet include 5.0 trillion cubic feet corresponding with two years growth at the long term growth rate. Having in mind the provisions of The Gas Resources Preservation Act, 1956, more than fifteen years of trend history, and the suggestion of many interveners at the hearings that at least five years trend gas be used in assessing the availability of gas to meet Alberta's requirements, the Board believes the use of two years' growth is justified and conservative.

On this basis, the Board estimates the surplus of gas within the Province to be 5.6 trillion cubic feet after allowing for protection of deliveries at the maximum daily rates authorized and anticipated in the permits. Upon expiration of the permits a further 3.1 trillion cubic feet would become surplus.

Details of the Board's analysis of these matters appear in Appendices D and E.

5. IN THE MATTER OF THE APPLICANTS' REQUESTS FOR AUTHORIZATION FOR THE REMOVAL OF ADDITIONAL QUANTITIES OF GAS AND THE SURPLUS WHICH WOULD RESULT IF THE REQUESTS WERE APPROVED

Trans-Canada requested authority to remove an additional 2.480 trillion cubic feet, consisting of 0.330 trillion cubic feet from fields included in its present permit and 2.150 trillion cubic feet from new fields. The Board disagrees slightly with the applicant's estimate of reserves in the new fields and in some of the permitted fields. The Board's estimate of the reserves available in both types of fields in excess of the amount now authorized is 2.440 trillion cubic feet.

Alberta and Southern requested authority to remove an additional 2.322 trillion cubic feet from fields now in its permits and from nine new fields, an amount less than that estimated by the applicant and the Board to be available in the fields.

The Board finds that the additional volume of gas requested by Alberta and Southern and the Board's estimate of the additional volume available in the fields requested by Trans-Canada, totalling 4.762 trillion cubic feet is surplus to the present and future annual and peak day requirements of the Province and may be produced within the requested term - although the reserves would not support full deliverability for the last several years of the term.

Were both those increased volumes requested by the applicants approved, the commitments of all permits would be increased from the present 18.7 trillion cubic feet of 1000 Btu gas, of which 3.1 trillion cubic feet is for the protection of deliveries at the maximum days authorized and anticipated in the permits, to 23.2 trillion cubic feet, of which 2.6 trillion cubic feet would be for the protection of the maximum days which the Board believes could be supported by the fields involved. The reduction from 3.1 to 2.6 trillion cubic feet occurs because an increased proportion of the total quantity of gas under permit would be produced at maximum rates limited by field productivity and good engineering practice rather than by permit stipulation. As a result less cushion gas is required in the terminal year. In addition, the reserves required to meet Alberta's thirty-year requirements would be increased by 0.2 trillion cubic feet to 16.3 trillion cubic feet. This increase represents the gas required by The Alberta Gas Trunk Line Company Limited system to move the additional volumes requested and increased process shrinkage at the Empress plant.

This would leave a surplus of gas of 0.9 trillion cubic feet having regard to the gas required to protect the maximum days authorized and anticipated in the permits. This surplus would be increased by 2.6 trillion cubic feet upon expiration of the permits.

Details of the Board's analyses relating to these matters are presented in Appendices D and F.

6. IN THE MATTER OF ANOTHER ASPECT OF THE APPLICATION OF TRANS-CANADA PIPE LINES LIMITED

The request that the existing and the newly applied for permit be consolidated into one.

The Board recognizes that consolidation of the permits would give the applicant greater operating flexibility and that it could be done without risk to the protection of Alberta consumers.

This aspect of the application is discussed in Appendix G.

7. IN THE MATTER OF CERTAIN OTHER ASPECTS OF THE APPLICATION OF ALBERTA AND SOUTHERN GAS CO. LTD.

(1) The request for an extension in the term of its present permits.

The Board agrees with the applicant that an extension in the term of the present permits is necessary to permit the applicant to remove the additional gas applied for. This is because of the addition to reserves and the delivery characteristics of the fields and the contracts which Alberta and Southern has entered into.

(2) The request that the permits be consolidated into one.

The Board recognizes that consolidation of the permits would give the applicant greater operating flexibility and that it could be done without risk to the protection of Alberta consumers.

(3) The request that the Parkland Field be deleted from the present permit.

The Board agrees with the applicant that the Parkland Field is now incapable of producing gas, and, therefore, that the field should be deleted from the permit.

(4) The request that some flexibility be permitted in the daily volumes authorized in the permits.

The Board agrees with the applicant that for the purposes of alleviating temporary operating problems caused by pipe line or equipment failure, the volume of gas that may be removed in any one day be 110 per cent of the maximum day volume specified in the permit.

These aspects of the applications are discussed in Appendix G.

8. IN THE MATTER OF THE DISPOSITION OF THE APPLICATION OF TRANS-CANADA PIPE LINES LIMITED

All things considered, the Board is prepared, with the approval of the Lieutenant Governor in Council, to rescind the existing Permit No. TC 64-5 and to issue a new permit to Trans-Canada Pipe Lines Limited authorizing it to remove, including the volume removed under its present and its earlier permits, 12.080 trillion cubic feet of gas from Alberta, the permit to be in the form shown in Appendix H and subject to the terms and conditions therein contained.

9. IN THE MATTER OF THE DISPOSITION OF THE APPLICATION OF ALBERTA AND SOUTHERN GAS CO. LTD.

All things considered, the Board is prepared, with the approval of the Lieutenant Governor in Council, to rescind the existing Permit No. AS 59-1 and Permit No. AS 60-2, and to issue a new permit to Alberta and Southern Gas Co. Ltd., authorizing it to remove, including the volume removed under its present permits, 6.450 trillion cubic feet of gas from Alberta, the permit to be in the form shown in Appendix I and subject to the terms and conditions therein contained.

Respectfully submitted,

G. W. Govier, P.Eng.,
Chairman.

A. F. Manyluk, P.Eng.,
Deputy Chairman.

V. Millard,
Board Member.

Dated at Calgary, Alberta,
this 10th day of November, 1964.

APPENDIX A

THE ESTABLISHED RESERVES OF GAS IN ALBERTA

The Board estimates that the initial marketable reserves of gas in Alberta have increased from some 36.7 trillion cubic feet as of December 31, 1963, to some 39.8 trillion cubic feet as of June 30, 1964, - an increase of 3.1 trillion cubic feet during the six-month period.

To June 30, 1964, a total of some 4.1 trillion cubic feet of marketable gas have been produced, 0.3 trillion of which were produced during the first six months of 1964.

The remaining marketable gas at June 30, 1964, is estimated to be 35.7 trillion cubic feet (equivalent to 37.6 trillion cubic feet of 1000 Btu gas), an increase of some 2.8 trillion cubic feet since December 31, 1963. Of the total of 35.7 trillion cubic feet, the Board considers that some 32.3 trillion cubic feet are presently within economic reach.

The major portion of the substantial increase is due to the appreciation of discoveries made in previous years, and to the re-evaluation of reserves, particularly in the western or foothills area of the Province. At both hearings, the Board received considerable evidence from operators giving information previously not made available. This evidence consisted primarily of the operators' interpretation of seismic data to delineate the areal extent of gas bearing formations in a number of areas. Historically, the Board has given some weight to seismic evidence when estimating the reserves of gas.

But, prior to the recent hearings, the amount of seismic information available to the Board was very limited. In its present estimate of reserves, the Board has continued its policy of giving partial weight to seismic interpretation of the areal extent of pools.

The number of new discoveries during the first half of 1964 was not much different from what has been experienced in the past few years. The Board's present estimate of the new reserves of gas discovered during the first six months of 1964 is some 140 billion cubic feet. Notwithstanding the low reserve, and having in mind the very early stage of development of the new discoveries - in many cases only the discovery well has been drilled - and the evidence presented at the hearings by operators suggesting that some of the recent discoveries are expected to result in large reserves, the Board considers the finds of the first half of 1964 to have a greater likelihood of being developed into sizeable reserves than have the discoveries of 1963.

The Board, in its estimate of reserves, considered evidence presented at the hearings by Trans-Canada and Alberta and Southern, and by the operators both at the hearings and at various times during the year, as well as studies of its staff.

The applicants' and the Board's estimate of the reserves of initial established marketable gas in the fields from which each applicant is now removing or expects to be removing gas and the areas from which they have applied to remove gas are compared in the following tabulation:

Fields and Areas Controlled by	Applicant's Estimate Tcf	Board's Estimate Tcf
Alberta and Southern	6.9	7.3
Trans-Canada	12.6	12.1
	19.5	19.4

While there is general agreement in the overall estimate of reserves, there are differences in the estimates for some of the individual fields. Furthermore, operators active in certain of the fields and areas presented detailed estimates of reserves, which, in some cases differed from those of the applicant and the Board. The more significant differences and the reasons for variation are presented in the succeeding tabulation:

Field or Area	Zone	Estimator	Initial Established Reserves Bcf	Remarks
Atlee-Buffalo	All zones	Trans-Canada Board	52 146	Trans-Canada's estimate is for a limited area.
Bigstone	Leduc	Alberta and Southern Trans-Canada Pan American Board	364 337 432 250	Operator's and applicants' area is based on seismic data and is greater than the Board's.
Burnt Timber	Mississippian	Shell Board	473 250	Shell area based on seismic and is greater than Board area.

Field or Area	Zone	Estimator	Initial Established Reserves Bcf	Remarks
Crossfield	Turner Valley	Shell	1113	Shell area larger than Board's. Difference in engineering factors.
		Board	1000	
Crossfield East	All zones	Trans-Canada	314	Difference in area and engineering factors.
		Board	220	
Edson	Mississippian	Trans-Canada	1956	Board's area less than Hudson's Bay's and Trans-Canada's.
		Hudson's Bay	1897	
		Board	1500	
Gilby	All zones	Trans-Canada	643	Difference in areal extent.
		Board	540	
Hussar	All zones	Trans-Canada	615	Difference in areal extent.
		Board	482	
Kaybob	Notikewin	Alberta and Southern	319	Difference in areal extent.
		Pacific	347	
		Board	240	
Minnehik-Buck Lake - Wilson Creek - Blindman River	Mississippian	Alberta and Southern	574	Difference in areal extent.
		Board	455	
Pine Northwest	Leduc	Alberta and Southern	152	Applicants' and Pan American area based on seismic; Board area smaller.
		Trans-Canada	174	
		Pan American	191	
		Board	100	
Olds	Wabamun	Trans-Canada	369	Difference in areal extent.
		Board	250	

Field or Area	Zone	Estimator	Initial Established Reserves Bcf	Remarks
Princess	All zones	Trans-Canada	110	Board area greater than Trans-Canada's.
		Board	221	
Provost	All zones	Trans-Canada	741	Difference in areal extent.
		Board	555	
Waterton	All zones	Alberta and Southern	964	Alberta and Southern has smaller area and different engineering factors.
		Shell	1296	
		Board	1260	
Wildcat Hills	Mississippian	Alberta and Southern	434	Difference in engineering factors.
		Board	550	

In addition to the preceding estimates, the applicants and some producers presented estimates for certain areas not now included in permits nor requested be included. Remarks for the areas where significant differences in the estimates of the various estimators are presented in the following tabulation:

Field or Area	Zone	Estimator	Initial Established Reserves Bcf	Remarks
Jumping Pound West	Mississippian	Trans-Canada	440	Trans-Canada estimate made before two additional wells drilled. Shell's area is based on seismic data and is larger than Board's.
		Shell	869	
		Board	700	

Field or Area	Zone	Estimator	Initial Established Reserves Bcf	Remarks
Marten Hills	Wabiskaw	Trans-Canada Pan American Board	614 1035 450	Board's proved area considerably smaller than Trans-Canada's or Pan American's. Pan American considers 75% of probable reserve in established reserve; Board and Trans-Canada use 50%. Pan American engineering factors differ from that used by Board and Trans-Canada.
Marten Hills	Wabamun	Trans-Canada Pan American Board	411 580 200	Difference due to reasons similar to those discussed opposite Wabiskaw zone.
Rolling Hills-Alderson	Second White Specks	Trans-Canada Canadian Pacific Board	139 270 100	Difference in area extent.

During the period January 1 to June 30, 1964, in the Province as a whole, there have been a number of discoveries and some changes in the estimate of remaining marketable reserves in certain of the previously known pools. The more significant ones are indicated in the following tabulation:

Area	Zone	Board's Estimate as of Dec.31 1963 Bcf	June 30 1964 Bcf	Change Bcf	Remarks
Beaverhill Lake-Fort Saskatchewan	Viking	300	434	+134	Pressure decline study indicates a common reservoir.
Benjamin Creek	Mississippian	50	150	+100	Formerly called Waiporous Creek. Additional data.
Bigstone	Leduc	50	250	+200	Additional data.
Burnt Timber	Mississippian	120	250	+130	Additional data.
Carstairs	Mississippian	834	700	-134	New drilling.
Crossfield	Mississippian	1359	1540	+181	Additional data.
Edson	Mississippian	900	1500	+600	New drilling.
Jumping Pound West	Mississippian	100	700	+600	New drilling and additional data.
Marten Hills	Wabamun	40	450	+410)	New drilling and additional data.
		100	200	+100)	
Pine Creek	Leduc	464	321	-143	Disappointing reservoir behavior.
Waterton	Mississippian	673	1085	+412	New drilling and additional data.
	Wabamun	197	126	- 71	

The Board's estimates of established reserves are presented in Table A-1. The table does not show individually fields or areas having a marketable reserve of less than ten billion cubic feet unless the reserve is supplying a market. However, the sum of these reserves is shown at the end of the table, and is included in the provincial total. The location of the fields and areas contained in Table A-1 is shown on Figure A-1.

TABLE A-1

ESTABLISHED RESERVES OF GAS IN ALBERTA, JUNE 30, 1964

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	(7) REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	(8) ESTIMATED HEATING VALUE BTU PER CU. FT.	(9) REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	(10) REMARKS
ACHESON	VIKING	4	25/5	3	-	3	1020	3	GAS SOLD TO NORTHWESTERN UTILITIES, LIMITED.
	BASAL BLAIRMORE	37	20/15	25	2	23	1020	23	
	LEDUC SOLUTION	81	45/55	20	4	16	1140	18	
ACHESON EAST	BASAL BLAIRMORE	12	15/5	10	-	10	1090	11	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
ADEN	BOW ISLAND	5	20/5	4	-	4	1000	4	
	BASAL COLORADO	6	15/5	5	1	4	1000	4	GAS SOLD TO CANADIAN MONTANA GAS COMPANY LTD.
	MANNVILLE	2	10/5	2	-	2	1000	2	
	SUNBURST-ELLIS	16	20/5	12	1	11	1040	11	
	MISSISSIPPIAN	19	10/10	15	3	12	1040	12	
ALDERSON	SECOND WHITE SPECKS	140	20/10	100	-	100	995	100	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	BOW ISLAND	8	20/5	6	-	6	1000	6	INCLUDES AREA FORMERLY CALLED BANTRY SOUTH.
ALEXANDER	BASAL BLAIRMORE	120	10/5	110	87	23	1060*	24	GAS SOLD TO NORTH CANADIAN OILS LIMITED AND CALGARY POWER LTD.
ALIX	BASAL BLAIRMORE	12	10/5	10	-	10	1090	11	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	NISKU ASSOCIATED	7	15/10	5	-	5	1130	6	
ANTELOPE	VIKING	39	20/5	15	-	15	1020	15	
	BANFF	11	20/5	9	-	9	1020	9	
ATHABASCA	GRAND RAPIDS	6	15/5	5	1	4	1030	4	SUPPLIES LOCAL UTILITY.
	WABAMUN	4	10/5	3	-	3	1020	3	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	(7) REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	(8) ESTIMATED HEATING VALUE BTU PER CU. FT.	(9) REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	(10) REMARKS
Athabasca East	Wabamun	2	10/5	2	1	1	1000	1	Supplies local utility.
Atlee-Buffalo	Bow Island	120	25/5	85	6	79	960*	76	Gas sold to Trans-Canada Pipe Lines Limited.
	Basal Colorado	7	15/5	6	-	6	1020	6	
	Basal Blairmore	72	20/5	55	1	54	960*	52	
Bantry	Milk River	46	20/5	35	-	35	960	34	Supplies local utility.
	Bow Island	20	20/5	15	-	15	970	15	Presently considered beyond economic reach.
	Basal Colorado	1	15/5	1	-	1	970	1	
	Basal Blairmore Associated	20	20/5	15	-	15	1160	17	
Bashaw	Basal Blairmore	12	15/5	10	-	10	970	10	Presently considered beyond economic reach.
	Leduc Associated	17	15/30	10	-	10	1220	12	
Bawlf	Viking	11	25/5	8	-	8	1020	8	Presently considered beyond economic reach.
	Blairmore	3	20/5	2	-	2	1050	2	
Beaver Creek	Wabamun	94	15/50	40	-	40	1050*	42	
Beaverhill Lake-Fort Saskatchewan	Viking	620	15/5	500	66	434	1000	434	Gas sold to Northwestern Utilities, Limited and Mid-Western Industrial Gas Ltd.
	Blairmore	4	15/5	3	-	3	1000	3	
Belloy	Notikewin	9	20/5	7	-	7	1000	7	
	Gething	62	15/5	50	-	50	1000	50	
	Mississippian	23	10/5	20	-	20	1120	22	
Bellshill Lake	Viking	6	25/5	4	-	4	1040	4	Presently considered beyond economic reach.
	Blairmore	37	15/5	30	-	30	990	30	
	Blairmore Associated	3	15/10	2	-	2	990	2	
Benjamin Creek	Mississippian	230	20/20	150	-	150	1070	161	Formerly called Waiporous Creek.
Berland River	Leduc	440	10/25	300	-	300	1000	300	

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
FIELD OR AREA	ZONE	INITIAL GAS IN PLACE BCF	LOSSES RESERVOIR/SURFACE PER CENT	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	ESTIMATED HEATING VALUE BTU PER CU. FT.	REMAINING MARKETABLE GAS AT 1000 BTU PER CU. FT. BCF	REMARKS
Berland River West	Wabamun	24	10/30	15	-	15	1020	15	Presently considered beyond economic reach.
Bigoray	Blairmore	14	15/5	11	-	11	1080	12	
	Mississippian	13	15/10	10	-	10	1080	11	
Bigstone	Gething	23	10/5	20	-	20	1100	22	
	Dunvegan	29	10/5	25	-	25	1140	29	
	Wabamun	10	15/40	5	-	5	1050	5	
	Leduc	390	15/25	250	-	250	930	233	
Bindloss	Viking	430	15/5	350	50	300	970*	291	Gas sold to Trans-Canada Pipe Lines Limited.
	Basal Blairmore	31	15/5	25	-	25	990	25	
Bittern Lake	Viking	3	25/5	2	-	2	1020	2	
	Basal Blairmore	43	15/5	35	-	35	1070	37	
Black Butte	Bow Island	21	15/5	17	1	16	1010	16	Gas sold to Canadian Montana Gas Company Ltd.
	Basal Colorado	25	15/5	20	4	16	1000	16	
	Mannville	6	15/5	5	-	5	1000	5	
	Sunburst-Ellis	35	10/5	30	18	12	1000	12	
	Mississippian	12	15/5	10	2	8	1020	8	
Blueridge	Detrital	14	10/5	12	-	12	1100	13	Presently considered beyond economic reach.
	Mississippian	1	20/5	1	-	1	1130	1	
Bolloque Lake	Viking	3	25/5	2	-	2	1040	2	Presently considered beyond economic reach.
	Basal Blairmore	11	25/5	8	-	8	1100	9	
Bonnie Glen	Viking	3	15/10	2	-	2	1050	2	
	Blairmore	5	15/10	4	3	1	1100	1	Gas sold to Northwestern Utilities, Limited.
	Leduc Associated	430	10/15	330	8	322	1220	393	
	Leduc Solution	510	40/25	230	33	197	1220	240	
Bonnyville	Blairmore	5	20/5	4	2	2	980	2	Supplies local utility.

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	(7) REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	(8) ESTIMATED HEATING VALUE BTU PER CU. FT.	(9) REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	(10) REMARKS
BOUNDARY LAKE SOUTH	CADOMIN	8	20/10	6	-	6	1060	6	
	BOUNDARY LAKE	1	15/10	1	-	1	1050	1	
	MISSISSIPPIAN	43	15/5	35	9	26	1040*	27	GAS SOLD TO WEST-COAST TRANSMISSION COMPANY LIMITED.
BOW ISLAND	BOW ISLAND	20	20/5	15	-5	20	1110	22	CANADIAN WESTERN NATURAL GAS COMPANY LIMITED STORAGE RESERVOIR.
BOYLE-MUSTANG-AMISK LAKE	BLAIRMORE	7	25/5	5	-	5	1000	5	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	NISKU	6	15/5	5	-	5	990	5	
BRAEBURN	CADOMIN	10	15/5	8	-	8	1060	8	
	TRIASSIC	33	15/10	25	-	25	1090	27	
	PERMO-PENN	52	15/10	40	-	40	1030	41	
BRAZEAU RIVER	MISSISSIPPIAN	200	15/10	150	-	150	1040	156	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
BROOKS	MILK RIVER	9	20/5	7	3	4	990	4	SUPPLIES LOCAL UTILITY.
BROOKS NORTH-EAST	BOW ISLAND	14	25/5	10	-	10	960	10	
	BASAL COLORADO	1	20/5	1	-	1	1000	1	
	MANNVILLE	22	20/5	17	2	15	1030	16	SUPPLIES LOCAL UTILITY.
	DETRITAL	11	15/5	9	-	9	1030	9	
BROWN CREEK	MISSISSIPPIAN	59	20/15	40	-	40	970	39	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
BURNT RIVER	PEACE RIVER	2	10/5	2	-	2	1010	2	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	BLUESKY	9	10/5	8	-	8	1020	8	
BURNT TIMBER	MISSISSIPPIAN	390	20/20	250	-	250	1080	270	
CAMPBELL-NAMAO	BLAIRMORE ASSOCIATED AND SOLUTION	33	20/5	25	8	17	1020	17	GAS SOLD TO CANADIAN INDUSTRIAL GAS LIMITED.

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	(7) REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	(8) ESTIMATED HEATING VALUE BTU PER CU. FT.	(9) REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	(10) REMARKS
Carbon	Viking	7	20/5	5	-	5	1020	5	
	Basal Colorado	4	15/5	3	-	3	1020	3	
	Blairmore	150	15/5	120	4	116	1100	128	Gas sold to Canadian Western Natural Gas Company Limited.
	Mississippian	12	15/5	10	-	10	1080	11	
Caroline	Basal Blairmore	16	15/10	12	-	12	1070	13	
Carson Creek	Beaverhill Lake	320	15/15	230	-	230	1050	242	Reservoir being cycled.
Carson Creek North	Beaverhill Lake Associated	28	15/15	20	-	20	1100	22	
	Beaverhill Lake Solution	420	55/20	150	1	149	1100	164	Gas injected into Carson Creek.
Carson Lake	Mississippian	12	10/10	10	-	10	1050	11	Presently considered beyond economic reach.
Carstairs	Basal Blairmore	5	15/10	4	-	4	1100	4	
	Mississippian	1000	15/10	800	100	700	1100*	770	Gas sold to Trans-Canada Pipe Lines Limited.
Castor	Viking	5	20/5	4	-	4	1000	4	
	Blairmore	2	10/5	2	-	2	1000	2	Supplies local utility.
Cessford	Viking	170	20/5	130	2	128	1020	131	Gas sold to Trans-Canada Pipe Lines Limited.
	Basal Colorado	1300	20/5	1000	180	820	1020	836	
	Basal Blairmore	430	15/5	350	28	322	1020	328	
Chigwell	Blairmore	74	10/10	60	5	55	1100*	61	Gas sold to Trans-Canada Pipe Lines Limited.
Chinook Ridge	Paddy	12	10/10	10	-	10	1020	10	Presently considered beyond economic reach.
	Cadotte	31	10/10	25	-	25	1020	26	
	Notikewin	19	10/10	15	-	15	1020	15	

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	(7) REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	(8) ESTIMATED HEATING VALUE BTU PER CU. FT.	(9) REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	(10) REMARKS
Chisholm	Blairmore	12	10/5	10	-	10	1020	10	Presently considered beyond economic reach.
Clear Hills	Gething	1	15/5	1	-	1	980	1	Presently considered beyond economic reach.
	Triassic	8	10/5	7	-	7	1030	7	
	Leduc	4	15/5	3	-	3	1070	3	
Clive	Viking	4	20/5	3	-	3	990	3	Presently considered beyond economic reach.
	Blairmore	7	15/5	6	-	6	1020	7	
	Nisku Associated	7	10/15	5	-	5	1150	6	
	Leduc Associated	7	10/25	5	-	5	1200	6	
Cold Lake	Blairmore	6	25/5	4	2	2	1000	2	Supplies local utility.
Comrey	Second White Specks	4	20/5	3	-	3	940	3	
	Bow Island	29	10/5	25	12	13	940	12	Gas sold to Canadian Montana Gas Company Ltd.
Connorsville	Viking	7	20/5	6	-	6	990	6	
	Basal Blairmore	62	15/5	50	-	50	1130	57	
Control	Viking	22	15/5	18	-	18	970	17	Presently considered beyond economic reach.
	Basal Mannville	20	20/5	15	-	15	1030	15	
Countess	Bow Island	92	20/5	70	2	68	960*	65	Gas sold to Trans-Canada Pipe Lines Limited.
	Basal Colorado	140	25/5	100	34	66	960*	63	
	Basal Blairmore	40	20/5	30	2	28	960	27	
	Mississippian	2	15/5	2	-	2	960	2	
	Mississippian Associated	3	20/10	2	-	2	960	2	
Craigend	Grand Rapids	1	25/5	1	-	1	1000	1	Presently considered beyond economic reach.
	Grosmont	140	25/5	100	-	100	1000	100	
Crossfield	Cardium Solution	68	60/45	15	-	15	1120	17	
	Basal Blairmore	20	15/10	15	-	15	1100	17	
	Mississippian	2000	10/10	1650	110	1540	1080*	1663	Gas sold to Alberta and Southern Gas Co. Ltd. and Westcoast Transmission Company Limited.
	Wabamun	1400	15/50	600	24	576	1060*	611	

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
FIELD OR AREA	ZONE	INITIAL GAS IN PLACE BCF	LOSSES RESERVOIR/SURFACE PER CENT	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	ESTIMATED HEATING VALUE BTU PER CU. FT.	REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	REMARKS
Crossfield East	Mississippian	130	10/15	100	-	100	1120	112	
	Wabamun	350	15/60	120	-	120	1060	127	
Dixonville	Gething	12	10/5	10	-	10	1000	10	Presently considered beyond economic reach.
Donalda	Viking	40	20/5	30	-	30	970	29	Presently considered beyond economic reach.
	Basal Blairmore	5	15/5	4	-	4	970	4	
	Detrital	5	20/5	4	-	4	990	4	
Dowling Lake	Basal Blairmore	5	20/5	4	1	3	1150	3	Supplies local utility.
Drumheller	Viking	4	25/5	3	-	3	1100	3	
	Blairmore	23	10/5	20	-	20	1100	22	
Duvernay	Viking	4	20/5	3	2	1	980	1	Gas sold to Western Minerals Ltd. Plant and supplies local utility.
Dyberg	Belly River	3	20/5	2	-	2	950	2	Presently considered beyond economic reach.
	Viking	8	10/5	7	-	7	1000	7	
	Basal Blairmore	12	10/5	10	-	10	1020	10	
Eaglesham	Gething	6	15/5	5	-	5	1000	5	
	Cadomin	7	10/5	6	-	6	1060	6	
	Mississippian	99	10/5	85	-	85	1110	94	
Edson	Gething	24	15/10	18	-	18	1050	19	
	Mississippian	2100	15/15	1500	-	1500	1030	1545	
Elk Point	Mannville	4	25/5	3	1	2	990	2	Supplies local utility.
Ellerslie	Blairmore	3	20/5	2	-	2	1000	2	Gas sold to Steelman Gas Ltd.
Enchant	Milk River	5	30/5	3	-	3	1030	3	
	Bow Island	25	25/5	18	-	18	1030	19	
	Basal Blairmore	10	20/10	7	1	6	1030	6	Gas sold to Trans-Canada Pipe Lines Limited.
	Ellis	3	25/10	2	-	2	1030	2	
	Mississippian	5	15/10	4	1	3	1030	3	

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	(7) REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	(8) ESTIMATED HEATING VALUE BTU PER CU. FT.	(9) REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	(10) REMARKS
Erskine	Viking	4	20/5	3	-	3	1040	3	Presently considered beyond economic reach.
	Blairmore	26	15/10	20	-	20	1090	22	
	Leduc Associated	31	10/20	22	-	22	1070	24	
	Leduc Solution	10	35/25	5	-	5	1110	6	
Esther	Victoria	23	30/5	15	-	15	990	15	
	Banff	12	10/5	10	-	10	1000	10	
Etzikom	Bow Island	79	20/5	60	25	35	930	33	Gas sold to South Alberta Pipe Lines Ltd.
	Basal Blairmore	1	25/5	1	-	1	1010	1	
Excelsior	Viking	9	15/5	7	-	7	1000	7	
	Basal Blairmore	39	10/5	33	-	33	970	32	
Eyremore	Bow Island	15	30/5	10	-	10	960	10	Presently considered beyond economic reach.
Fairydell-Bon Accord	Viking	130	20/5	100	12	88	1020	90	Gas sold to Northwestern Utilities, Limited.
	Basal Blairmore	20	20/5	15	-	15	1000	15	
Faust South	Gething	12	10/5	10	-	10	990	10	Presently considered beyond economic reach.
Fenn-Big Valley	Viking	20	20/5	15	4	11	1000	11	Gas sold to Northwestern Utilities, Limited and Trans-Canada Pipe Lines Limited.
	Nisku Solution	150	45/35	53	16	37	1110	41	
	Leduc Associated and Solution	11	35/45	4	1	3	1110	3	
Figure Lake	Viking	6	25/5	4	-	4	960	4	Presently considered beyond economic reach.
	Blairmore	11	15/5	9	-	9	1000	9	
	Nisku	19	15/5	15	-	15	1000	15	
Foremost	Bow Island	33	15/5	27	6	21	950	20	Gas sold to Canadian Western Natural Gas Company Limited.
Fort Kent	Blairmore	5	20/5	4	1	3	980	3	Supplies local utility.

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	(7) REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	(8) ESTIMATED HEATING VALUE BTU PER CU. FT.	(9) REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	(10) REMARKS
FOX CREEK	VIKING	6	15/5	5	-	5	1160	6	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	GETHING	1	25/5	1	-	1	1160	1	
	TRIASSIC	5	15/10	4	-	4	1160	5	
FOX CREEK WEST	GETHING	5	10/5	4	-	4	1020	4	
	NISKU	18	10/20	13	-	13	1150	15	
GARRINGTON	VIKING ASSOCIATED AND NON-ASSOCIATED	130	20/10	90	-	90	1130	102	GARRINGTON INCLUDES AREA FORMERLY CALLED RAVEN RIVER.
	BLAIRMORE	20	15/10	15	-	15	1010	15	
	MISSISSIPPIAN	26	15/10	20	-	20	1020	20	
	LEDUC	37	15/20	25	-	25	1020	26	
GHOST PINE	BLAIRMORE	37	10/10	30	-	30	1010	30	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	BLAIRMORE ASSOCIATED	8	20/10	6	-	6	1050	6	
	MISSISSIPPIAN	3	15/10	2	-	2	1070	2	
GILBY	VIKING	4	20/5	3	-	3	1220	4	
	VIKING SOLUTION	14	40/40	5	-	5	1250	6	
	BLAIRMORE	130	10/15	100	5	95	1160	110	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED.
	BLAIRMORE SOLUTION	25	40/40	9	-	9	1250	11	
	JURASSIC	200	10/15	150	2	148	1020	151	
	JURASSIC SOLUTION	42	40/40	15	-	15	1100	17	
	PEKISKO	330	10/15	250	30	220	1080	238	
	BANFF	4	20/15	3	-	3	1100	3	
	WABAMUN	7	10/20	5	-	5	1170	6	
GLEN PARK	BASAL BLAIRMORE	9	15/5	7	1	6	1140	7	GAS SOLD TO NORTHWESTERN UTILITIES, LIMITED.
	LEDUC SOLUTION	17	40/20	8	1	7	1250	9	
GOLD CREEK	WABAMUN	50	15/30	30	-	30	1050	32	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
GOLDEN SPIKE	VIKING	4	20/5	3	1	2	1050	2	GAS INJECTED INTO LEDUC ZONE.
	BLAIRMORE	22	10/5	19	1	18	1050	19	
	WABAMUN	26	10/15	20	7	13	1060	14	
	NISKU ASSOCIATED	4	15/15	3	-	3	1220	4	
	NISKU SOLUTION	6	35/20	3	1	2	1220	2	GAS INJECTED IN-LEDUC ZONE.
	LEDUC SOLUTION	150	30/30	75	-16	91	1290	117	
GOODWIN LAKE	JURASSIC	20	15/10	15	-	15	1070	16	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	(7) REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	(8) ESTIMATED HEATING VALUE BTU PER CU. FT.	(9) REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	(10) REMARKS
GORDONDALE	PADDY	53	15/5	43	22	21	1000	21	GAS SOLD TO WESTCOAST TRANSMISSION COMPANY LIMITED.
	NOTIKEWIN	4	20/5	3	-	3	1020	3	
	GETHING	68	15/5	55	24	31	1050	33	
GREENCOURT	JURASSIC-DETRITAL	65	15/10	50	-	50	1070	54	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	MISSISSIPPIAN ASSOCIATED	37	25/10	25	-	25	1130	28	
HACKETT	BASAL BLAIRMORE	62	10/10	50	-	50	1100	55	
HAIRY HILL	VIKING	1	25/5	1	-	1	980	1	
	BLAIRMORE	23	10/5	20	6	14	1000	14	GAS SOLD TO WESTERN MINERALS LTD. PLANT.
HAMELIN CREEK	CADOTTE	3	20/5	2	-	2	1000	2	
	GETHING	4	15/5	3	-	3	1010	3	
	CADOMIN	21	15/5	17	4	13	1060	14	SUPPLIES LOCAL UTILITY.
HAMILTON LAKE	VIKING ASSOCIATED AND NON-ASSOCIATED	14	25/5	10	-	10	1040	10	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	UPPER MANNVILLE	1	15/5	1	-	1	1040	1	
HARMATTAN EAST	MISSISSIPPIAN ASSOCIATED	1200	10/15	900	-14	914	1080	987	
	MISSISSIPPIAN SOLUTION	200	35/25	100	14	86	1280	110	GAS INJECTED INTO GAS CAP.
HARMATTAN-ELKTON	MISSISSIPPIAN	55	15/15	40	-	40	1040	42	
	MISSISSIPPIAN ASSOCIATED	1200	10/15	900	-15	915	1080	988	RESERVOIR BEING CYCLED.
	MISSISSIPPIAN SOLUTION	200	35/25	100	15	85	1280	109	GAS INJECTED INTO GAS CAP.
	LEDUC	83	10/60	30	-	30	1100	33	
HEART RIVER	CADOTTE	2	15/5	2	-	2	1000	2	SUPPLIES LOCAL UTILITY.
	NOTIKEWIN	2	10/5	2	-	2	1000	2	
HERCULES	VIKING	19	15/5	15	-	15	1050	16	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	BLAIRMORE	29	10/5	25	-	25	960	24	

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	(7) REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	(8) ESTIMATED HEATING VALUE BTU PER CU. FT.	(9) REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	(10) REMARKS
HESPERO	BASAL BLAIRMORE	65	15/10	50	-	50	1130	57	
	DETRITAL	1	15/5	1	-	1	1130	1	
	LEDUC ASSOCIATED	6	10/20	4	-	4	1150	5	
HOLBORNE	CARDIUM	6	25/5	4	-	4	980	4	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	BLAIRMORE	25	20/10	18	-	18	1120	20	
HOLMBERG	BLAIRMORE	25	15/5	20	-	20	1050	21	GAS SOLD TO BAROID OF CANADA, LTD. PLANT.
HOMEGLEN-RIMBEY	LEDUC ASSOCIATED AND SOLUTION	1000	10/15	800	100	700	1080	756	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED AND ALBERTA AND SOUTHERN GAS CO. LTD.
HUNTER VALLEY	MISSISSIPPIAN	78	15/25	50	-	50	1080	54	
HUSSAR	BELLY RIVER	3	30/5	2	-	2	1000	2	
	VIKING	70	25/5	50	2	48	1040	50	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED.
	BASAL COLORADO	53	20/5	40	6	34	1040*	35	
	BLAIRMORE	460	10/5	390	51	339	1040*	353	
INLAND	VIKING	21	25/5	15	-	15	980	15	
INNISFAIL	MISSISSIPPIAN	22	10/10	18	-	18	1080	19	
	WABAMUN	4	15/15	3	-	3	1170	4	
	LEDUC ASSOCIATED	17	10/35	10	-	10	1020	10	
	LEDUC SOLUTION	210	40/40	75	9	66	1110*	74	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED.
JARVIE	VIKING	9	20/5	7	-	7	1040	7	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	BLAIRMORE	7	10/5	6	-	6	1100	7	
JENNER	BOW ISLAND	4	25/5	3	-	3	990	3	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	BASAL COLORADO	4	10/5	3	-	3	1040	3	
	BLAIRMORE	11	15/5	9	-	9	1050	9	

(1) Field or Area	(2) Zone	(3) Initial Gas in Place BCF	(4) Losses Reservoir/Surface Per Cent	(5) Initial Marketable Gas BCF	(6) Marketable Gas Produced to June 30, 1964 BCF	(7) Remaining Marketable Gas to June 30, 1964 BCF	(8) Estimated Heating Value BTU per Cu. Ft.	(9) Remaining Marketable Gas at 1000 BTU per Cu.Ft. BCF	(10) Remarks
Joarcam	Viking Associated	66	20/5	50	-	50	1040	52	Presently considered beyond economic reach.
Joffre	Viking	1	25/5	1	-	1	1000	1	Presently considered beyond economic reach.
	Basal Blairmore	33	20/5	25	-	25	1020	26	
	Nisku Solution	100	40/40	36	-	36	1260	45	
	Leduc	3	15/10	2	-	2	1050	2	
Judy Creek	Viking	13	20/5	10	-	10	1020	10	
	Beaverhill Lake Solution	770	60/35	200	3	197	1080	213	Gas sold to Northwestern Utilities, Limited.
Jumping Pound	Mississippian	780	15/17	550	190	360	1050	378	Gas sold to Canadian Western Natural Gas Company Limited.
Jumping Pound West	Mississippian	1100	20/20	700	-	700	1050	735	Includes area previously called Morleyville.
Kaybob	Notikewin	300	15/5	240	21	219	1020	223	Gas sold to Alberta and Southern Gas Co. Ltd.
	Gething	15	15/5	12	-	12	1050	13	
	Cadomin	120	15/5	100	-	100	1040	104	
	Winterburn	5	15/35	3	-	3	1070	3	
	Beaverhill Lake Associated	4	20/15	3	-	3	1070	3	
	Beaverhill Lake Solution	330	60/25	100	2	98	1140	112	
Kaybob South	Viking	20	20/5	15	-	15	1100	17	
	Cadomin	74	15/5	60	-	60	1040	62	
	Triassic	4	20/5	3	-	3	1160	3	
	Triassic Solution	210	50/25	80	-	80	1160	93	
	Nisku	1	20/5	1	-	1	1240	1	
	Beaverhill Lake	24	10/30	15	-	15	1210	18	
Kessler	Viking	70	25/5	50	3	47	990	47	Gas sold to Trans-Canada Pipe Lines Limited.
	Mannville	5	10/5	4	-	4	990	4	

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
FIELD OR AREA	ZONE	INITIAL GAS IN PLACE BCF	LOSSES RESERVOIR/SURFACE PER CENT	INITIAL MARKETABLE GAS BCF	MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	ESTIMATED HEATING VALUE BTU PER CU. FT.	REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	REMARKS
Killam	Viking	4	25/5	3	-	3	1040	3	Presently considered beyond economic reach.
	Blairmore	9	15/5	7	-	7	1000	7	
Kirkcaldy	Basal Mannville	20	20/5	15	-	15	1000	15	
	Mississippian	39	15/10	30	-	30	1010	30	
Kneller	Blairmore	12	10/5	10	-	10	1100	11	Presently considered beyond economic reach.
Lac La Biche	Viking	14	25/5	10	-	10	1010	10	Presently considered beyond economic reach.
	Blairmore	20	20/5	15	-	15	1010	15	Supplies local utility.
Lambert Creek	Wabamun	15	25/10	10	-	10	1050	11	Presently considered beyond economic reach.
Leahurst	Blairmore	9	10/5	8	1	7	1100	8	Supplies local utility.
Leduc-Woodbend	Viking	20	20/5	15	3	12	1070	13	Injected into Nisku and Leduc gas caps.
	Basal Blairmore	85	20/5	65	14	51	1180	60	
	Nisku Associated	37	10/15	28	-2	30	1180	35	Gas sold to Northwestern Utilities, Limited.
	Nisku Solution	140	25/30	72	61	11	1180	13	
	Leduc Associated	420	15/15	300	-14	314	1180	371	
	Leduc Solution	170	40/30	70	62	8	1180	9	
Lindbergh	Viking	3	35/5	2	-	2	990	2	
	Blairmore	18	20/5	14	4	10	1100	11	Supplies salt plant.
Lloydminster	Blairmore	40	50/30	14	11	3	950	3	Supplies local utility.
Lone Pine Creek	Basal Blairmore	4	10/10	3	-	3	1020	3	
	Wabamun	160	20/20	100	-	100	1030	103	
	Leduc	3	15/20	2	-	2	1050	2	
Lookout Butte	Mississippian	550	15/15	400	-	400	1040	416	Reservoir being cycled.

(1) Field or Area	(2) Zone	(3) Initial Gas in Place BCF	(4) Losses Reservoir/Surface Per Cent	(5) Initial Marketable Gas BCF	(6) Marketable Gas Produced to June 30, 1964 BCF	(7) Remaining Marketable Gas to June 30, 1964 BCF	(8) Estimated Heating Value BTU per Cu. Ft.	(9) Remaining Marketable Gas at 1000 BTU per Cu. Ft. BCF	(10) Remarks
Lovett River	Blairmore	12	10/5	10	-	10	1040	10	Presently considered beyond economic reach.
	Mississippian	86	10/10	70	-	70	1040	73	
Majeau Lake	Blairmore	3	20/5	2	-	2	1000	2	Presently considered beyond economic reach.
	Mississippian	12	10/10	10	-	10	1070	11	
Manyberries	Bow Island	42	20/5	32	17	15	940	14	Gas sold to Canadian Montana Gas Company Ltd.
Marsh Head Creek	Leduc	27	15/35	15	-	15	1050	16	Presently considered beyond economic reach.
Marten Hills	Pelican	2	35/5	1	-	1	990	1	
	Grand Rapids	5	35/5	3	-	3	990	3	
	Wabiskaw	680	30/5	450	-	450	990	446	
	Wabamun	300	30/5	200	-	200	1000	200	
Mazeppa	Mississippian	20	10/15	15	-	15	1060	16	Presently considered beyond economic reach.
Medicine Hat	Medicine Hat	2300	20/5	1750	300	1450	950*	1378	Gas sold to Trans-Canada Pipe Lines Limited, Many Islands Pipe Lines Limited and supplie local utility.
	Bow Island	20	20/5	15	-	15	970	15	
	Ellis	25	15/5	20	-	20	1000	20	
Medicine River	Blairmore Solution Associated and Non-Associated	53	20/5	40	-	40	1150	46	
	Blairmore Solution	18	40/45	6	-	6	1250	8	
	Jurassic Associated and Non-Associated	33	20/5	25	-	25	1020	26	
	Jurassic Solution	52	65/45	10	-	10	1100	11	
	Mississippian Associated and Non-Associated	13	20/5	10	-	10	1100	11	
	Mississippian Solution	9	40/45	3	-	3	1200	4	

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	(7) REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	(8) ESTIMATED HEATING VALUE BTU PER CU. FT.	(9) REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	(10) REMARKS
Millet	Blairmore	21	20/10	15	-	15	1020	15	Presently considered beyond economic reach.
Minnehik-Buck Lake	Blairmore Mississippian	6 550	25/5 15/10	4 420	- 30	4 390	1000 1090	4 425	Gas sold to Alberta and Southern Gas Co. Ltd.
Moose Mountain	Mississippian	75	20/25	45	-	45	1000	45	Presently considered beyond economic reach.
Morinville	Viking Blairmore	3 140	25/5 15/5	2 110	- 36	2 74	1000 1070	2 79	Gas sold to Canadian Industrial Gas Limited and supplies local utility.
Mountain Park	Triassic	29	10/5	25	-	25	1090	27	Presently considered beyond economic reach.
Nevis	Blairmore Devonian	65 880	15/10 15/20	50 600	- 69	50 531	1000 990*	50 526	Gas sold to Trans-Canada Pipe Lines Limited.
Nordegg	Triassic Mississippian	9 25	10/10 10/10	7 20	- -	7 20	1000 1000	7 20	Presently considered beyond economic reach.
Normandville	Gething Triassic Mississippian	15 4 31	15/5 15/5 15/5	12 3 25	- - 1	12 3 24	980 1090 1050	12 3 25	Supplies local utility.
Obed	Mississippian	12	10/10	10	-	10	1040	10	Presently considered beyond economic reach.
Oberlin	Blairmore	3	20/5	2	1	1	1090	1	Supplies local utility.

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	(7) REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	(8) ESTIMATED HEATING VALUE BTU PER CU. FT.	(9) REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	(10) REMARKS
OKOTOKS	WABAMUN	420	10/60	150	23	127	1000	127	GAS SOLD TO CANADIAN WESTERN NATURAL GAS COMPANY LIMITED.
OLDS	WABAMUN	370	15/20	250	-	250	1050	263	
OYEN	VIKING	43	15/5	35	3	32	960*	31	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED.
	DETRITAL	4	15/5	3	-	3	1140	3	
PADDLE RIVER	JURASSIC	190	25/10	130	-	130	1070	139	
	MISSISSIPPIAN	30	25/10	20	-	20	1060	21	
PAKOWKI LAKE	BOW ISLAND	14	25/5	10	3	7	940	7	GAS SOLD TO CANADIAN MONTANA GAS COMPANY LTD.
PARKLAND NORTH-EAST	MISSISSIPPIAN	21	15/15	15	-	15	1010	15	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
PEMBINA	BELLY RIVER ASSOCIATED AND NON-ASSOCIATED	94	10/5	80	-	80	1180	94	
	BELLY RIVER SOLUTION	48	40/65	10	1	9	1180	11	GAS SOLD TO NORTHWESTERN UTILITIES, LIMITED.
	CARDIUM SOLUTION	3100	60/35	800	160	640	1170	749	
	VIKING	11	10/5	9	-	9	1100	10	
	BLAIRMORE	210	10/10	170	9	161	1120	180	GAS SOLD TO ALBERTA AND SOUTHERN GAS CO. LTD.
	JURASSIC	18	10/5	15	-	15	1050	16	
	MISSISSIPPIAN	13	10/15	10	-	10	1050	11	
PENDANT D'OREILLE	BOW ISLAND	180	20/5	140	73	67	940	63	GAS SOLD TO CANADIAN MONTANA GAS COMPANY LTD.
	MANNVILLE	25	15/5	20	6	14	1000	14	
PENHOLD	VIKING	14	10/5	12	-	12	1020	12	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	(7) REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	(8) ESTIMATED HEATING VALUE BTU PER CU. FT.	(9) REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	(10) REMARKS
PHIL CAN	GETHING	12	20/5	9	-	9	980	9	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	MISSISSIPPIAN	5	15/5	4	-	4	1050	4	
PINCHER CREEK	MISSISSIPPIAN	1600	25/25	900	170	730	1030*	752	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED.
PINE CREEK	WABAMUN	100	10/50	45	-	45	1050*	47	
	LEDUC	780	25/35	380	59	321	1050*	337	GAS USED TO MAINTAIN PRESSURE IN WINDFALL FIELD.
PINE NORTH-WEST	LEDUC	180	15/35	100	-	100	1050	105	
PLAIN LAKE	VIKING	3	25/5	2	-	2	980	2	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	BLAIRMORE	28	20/5	21	-	21	1000	21	
PLOVER LAKE	VIKING	19	15/5	15	-	15	1000	15	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
POUCE COUPE	PEACE RIVER	140	15/5	110	60	50	1000	50	GAS SOLD TO WESTCOAST TRANSMISSION COMPANY LIMITED.
	CADOMIN	12	15/5	10	-	10	1060	11	
POUCE COUPE SOUTH	DOE CREEK	4	40/5	2	1	1	1000	1	GAS SOLD TO WESTCOAST TRANSMISSION COMPANY LIMITED AND PEACE RIVER TRANSMISSION CO. LTD.
	PEACE RIVER	110	15/5	90	40	50	1040	52	
	GETHING	14	10/5	12	8	4	1000	4	
	JURASSIC	1	25/10	1	-	1	1070	1	
PREVO	MISSISSIPPIAN	37	10/10	30	3	27	1100	30	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED.
PRINCESS	SECOND WHITE SPECKS	28	25/5	20	-	20	1000	20	
	BOW ISLAND	7	20/5	5	-	5	1010	5	

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	(7) REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	(8) ESTIMATED HEATING VALUE BTU PER CU. FT.	(9) REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	(10) REMARKS
PRINCESS (CONT)	BASAL COLORADO	39	20/5	30	1	29	1010*	29	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED.
	BASAL BLAIRMORE	160	15/5	130	15	115	1010*	116	
	MISSISSIPPIAN	8	20/5	6	-	6	1030	6	
	JEFFERSON	44	20/15	30	-	30	1030	31	
PROVOST	VIKING	710	20/5	540	120	420	1000*	420	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED.
	BLAIRMORE	19	15/5	15	-	15	1000	15	
REDLAND	VIKING	3	20/5	2	-	2	1000	2	
	BLAIRMORE	20	20/5	15	-	15	1050	16	
REDWATER	VIKING	14	25/5	10	-	10	1040	10	
	LEDUC SOLUTION	220	40/65	46	8	38	1220	46	GAS SOLD TO MID-WESTERN INDUSTRIAL GAS LTD.
RED WILLOW	VIKING	13	20/5	10	-	10	1020	10	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	BASAL BLAIRMORE	8	20/10	6	-	6	1100	7	
RETLAW	BOW ISLAND	3	25/5	2	-	2	950	2	
	BASAL COLORADO	3	25/5	2	-	2	1020	2	
	BASAL BLAIRMORE	56	20/10	40	-	40	1000	40	
RICH	BASAL BLAIRMORE	16	15/10	12	-	12	1100	13	
RICHDALE	VIKING	14	25/5	10	-	10	1010	10	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	BASAL BLAIRMORE	11	25/5	8	-	8	1050	8	
ROCHESTER	VIKING	5	20/5	4	-	4	1000	4	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	BLAIRMORE	27	25/5	19	-	19	1000	19	
	WABAMUN	6	10/5	5	-	5	1070	5	
ROLLING HILLS	BOW ISLAND	19	15/5	15	-	15	970	15	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	BASAL COLORADO	12	15/5	10	-	10	1030	10	
ROWLEY	VIKING	29	10/5	25	-	25	1040	26	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	MANNVILLE	9	10/5	8	-	8	1050	8	
	MISSISSIPPIAN ASSOCIATED	49	10/10	40	-	40	1080	43	

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Field or Area	Zone	Initial Gas in Place BCF	Losses Reservoir/Surface Per Cent	Initial Marketable Gas BCF	Marketable Gas Produced to June 30, 1964 BCF	Remaining Marketable Gas to June 30, 1964 BCF	Estimated Heating Value BTU per Cu. Ft.	Remaining Marketable Gas at 1000 BTU per Cu.Ft. BCF	Remarks
Rycroft	Gething	16	15/5	13	3	10	1040	10	Supplies local utility.
St. Albert-Big Lake	Viking	3	20/5	2	-	2	1070*	2	
	Blairmore	150	15/5	120	49	71	1070*	76	Gas sold to Canadian Industrial Gas Limited.
St. Brides	Blairmore	26	20/5	20	-	20	940	19	Presently considered beyond economic reach.
St. Paul	Blairmore	5	20/5	4	3	1	1010	1	Supplies local utility.
Saddle Hills	Peace River	41	10/5	35	-	35	1020	36	
	Gething	4	15/5	3	-	3	980	3	
	Permo-Penn	23	10/5	20	-	20	1030	21	
Samson	Basal Blairmore Associated and Non-Associated	19	20/10	14	4	10	1040	10	Gas sold to Northwestern Utilities, Limited.
Sarcee	Mississippian	210	15/15	150	13	137	1050	144	Gas sold to Canadian Western Natural Gas Company Limited.
Savanna Creek	Mississippian	590	10/25	400	13	387	1020	395	Gas sold to Westcoast Transmission Company Limited.
Sedalia	Viking	130	20/5	100	2	98	1010*	99	Gas sold to Trans-Canada Pipe Lines Limited.
	Blairmore	1	25/5	1	-	1	1010	1	
Sibbald	Viking	59	20/5	45	6	39	960*	37	Gas sold to Trans-Canada Pipe Lines Limited.
	Basal Colorado	13	20/5	10	-	10	970	10	

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	(7) REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	(8) ESTIMATED HEATING VALUE BTU PER CU. FT.	(9) REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	(10) REMARKS
SIEU RIVER	BLAIRMORE	15	15/5	12	-	12	1000	12	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
SIMONETTE	CADOMIN	20	15/10	15	-	15	1060	16	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	WABAMUN	140	10/35	80	-	80	1070	86	
	LEDUC SOLUTION	200	50/50	50	-	50	1020	51	
SMITH COULEE	BOW ISLAND	49	25/5	35	15	20	930	19	GAS SOLD TO CANADIAN MONTANA GAS COMPANY LIMITED.
SMOKY RIVER	WABAMUN	42	15/30	25	-	25	1050	26	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
STANDARD	VIKING	26	20/5	20	-	20	1000	20	
STEEN RIVER	SLAVE POINT	13	10/15	10	-	10	1070	11	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
STEEP CREEK	GETHING	6	15/5	5	-	5	1020	5	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	TRIASSIC	7	15/10	5	-	5	1030	5	
	PERMO-PENN	12	10/10	10	-	10	1030	10	
STETTLER	VIKING	4	25/5	3	-	3	1020	3	GAS USED FOR COMPRESSOR FUEL.
	NISKU SOLUTION	26	45/45	8	2	6	1130	7	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED AND NORTH-WESTERN UTILITIES, LIMITED.
	LEDUC SOLUTION	10	45/45	3	1	2	1140	2	
STOLBERG	MISSISSIPPIAN	86	10/10	70	-	70	1040	73	PRESENTLY CONSIDER BEYOND ECONOMIC RE
STRATHMORE	BELLY RIVER	7	20/5	5	-	5	1000	5	
	VIKING	7	20/5	5	-	5	1000	5	
STURGEON LAKE SOUTH	GETHING	16	15/5	13	-	13	1000	13	
	CADOMIN	6	15/5	5	-	5	1060	5	
	TRIASSIC ASSOCIATED	5	10/5	4	-	4	1180	5	
	TRIASSIC SOLUTION	20	35/70	4	-	4	1180	5	

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	(7) REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	(8) ESTIMATED HEATING VALUE BTU PER CU. FT.	(9) REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	(10) REMARKS
Sturgeon Lake South (cont)	Wabamun	7	10/25	5	-	5	1070	5	
	Leduc Associated	7	10/25	5	-	5	1080	5	
	Leduc Solution	230	45/45	70	8	62	1080	67	Gas sold to Canadian Utilities Limited.
Sturgeon Lake South General Area	Gething	80	15/5	65	-	65	1000	65	Presently considered beyond economic reach.
	Cadomin	31	15/5	25	-	25	1060	27	
	Triassic	6	15/5	5	-	5	1180	6	
	Permo-Penn	3	20/5	2	-	2	1030	2	
Suffield	Milk River	32	25/5	23	4	19	960	18	Supplies local utility.
Sundre	Viking	6	20/10	4	-	4	1020	4	
	Blairmore	8	15/10	6	-	6	1020	6	
	Elkton Associated	21	15/15	15	-3	18	1070	19	
	Elkton Solution	64	40/35	25	3	22	1100	24	Gas injected into gas cap.
Swalwell	Mississippian	12	10/10	10	-	10	1100	11	
Swan Hills	Gething	1	10/5	1	-	1	1050	1	
	Beaverhill Lake Solution	1400	55/40	380	3	377	1120	422	Gas sold to Northwestern Utilities, Limited.
Sylvan Lake	Blairmore	310	15/10	240	-	240	1100	264	
	Detrital	8	20/10	6	-	6	1100	7	
	Jurassic Associated and Non-Associated	49	20/10	35	-	35	1020	36	
	Jurassic Solution	12	40/45	4	-	4	1100	4	
	Mississippian	97	20/10	70	-	70	1100	77	
	Mississippian Solution	42	40/40	15	-	15	1200	18	
	Leduc Associated	35	20/10	25	-	25	1020	26	
	Leduc Solution	14	35/45	5	-	5	1100	6	
Tangent	Cadotte	14	30/5	9	-	9	1010	9	Presently considered beyond economic reach.
	Gething	79	20/5	60	-	60	1000	60	
	Triassic	53	20/5	40	-	40	1180	47	

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THREE HILLS CREEK	BELLY RIVER	9	15/5	7	-	7	970	7	
	VIKING	8	20/5	6	-	6	1000	6	
	MISSISSIPPIAN	210	10/10	170	6	164	1100*	180	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED.
	LEDUC	10	20/15	7	-	7	1100	8	
TURIN	BOW ISLAND	11	20/5	8	-	8	970	8	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	BASAL BLAIRMORE	21	10/5	18	-	18	1020	18	
	ELLIS	5	15/5	4	-	4	1070	4	
	MISSISSIPPIAN	3	15/10	2	-	2	1050	2	
TURNER VALLEY	MISSISSIPPIAN ASSOCIATED	1500	10/70	410	260	150	1110	167	GAS SOLD TO CANADIAN WESTERN NATURAL GAS COMPANY LIMITED AND SUPPLIES LOCAL UTILITY.
	MISSISSIPPIAN SOLUTION	1400	45/55	350	270	80	1110	89	
TWINING	BASAL MANNVILLE	1	20/5	1	-	1	1120	1	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	MISSISSIPPIAN	16	20/5	12	-	12	1100	13	
	MISSISSIPPIAN SOLUTION	15	40/35	6	-	6	1100	7	
TWINING NORTH	MANNVILLE	7	20/5	5	-	5	1100	6	
	MISSISSIPPIAN ASSOCIATED	40	20/5	30	-	30	1110	33	
	MISSISSIPPIAN SOLUTION	16	40/15	8	-	8	1110	9	
TWO CREEK	TRIASSIC	12	10/5	10	-	10	1090	11	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
USONA	BLAIRMORE	12	10/5	10	-	10	1110	11	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
VERGER	BOW ISLAND	1	25/5	1	-	1	1100	1	
	BASAL COLORADO	3	25/5	2	-	2	1060	2	
	BASAL MANNVILLE	50	20/5	38	-	38	1050	40	
	MISSISSIPPIAN	3	15/10	2	-	2	1070	2	

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Viking-Kinsella	Viking	1100	25/5	770	370	400	990	396	Gas sold to Northwestern Utilities, Limited and supplies local utility.
	Blairmore	33	20/5	25	10	15	1000	15	
	Devonian	16	20/5	12	3	9	1010	9	
Virginia Hills	Blairmore	9	10/5	8	-	8	1040	8	
	Triassic	20	15/10	15	-	15	1160	17	
	Beaverhill Lake								
	Solution	220	55/55	45	-	45	1120	50	Gas sold to Northwestern Utilities, Limited.
	Slave Point	3	25/20	2	-	2	1070	2	
Wainwright	Viking	5	15/5	4	-	4	980	4	
	Blairmore Associated and Non-Associated	33	20/30	18	-	18	940	17	
Waskahigan	Dunvegan	25	10/10	20	-	20	1100	22	Presently considered beyond economic reach.
Waterglen	Blairmore	7	15/10	5	-	5	1100	6	Presently considered beyond economic reach.
	Leduc	9	15/20	6	-	6	1100	7	
Waterton	Mississippian	2200	15/40	1130	45	1085	1020	1107	Gas sold to Alberta and Southern Gas Co. Ltd.
	Devonian	230	20/30	130	4	126	1020	129	
Watts	Viking	3	20/5	2	1	1	1040	1	Supplies local utility.
	Mississippian	1	20/5	1	-	1	1070	1	
Wayne-Rosedale	Belly River	7	20/5	5	-	5	1000	5	
	Viking	180	20/5	140	7	133	1100*	146	Gas sold to Canadian Western Natural Gas Company Limited, Trans-Canada Pipe Lines Limited, and supplies local utility.
	Blairmore	220	15/5	180	14	166	1100*	183	

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WEST DRUMHELLER	BASAL BLAIRMORE	12	15/5	10	-	10	1100	11	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	NISKU ASSOCIATED	9	10/15	7	-	7	1090	8	
WESTEROSE	BLAIRMORE	7	20/5	5	-	5	1020	5	
	LEDUC ASSOCIATED	130	10/20	90	-8	98	1070	105	
	LEDUC SOLUTION	130	30/20	73	8	65	1100	72	GAS INJECTED INTO GAS CAP.
WESTEROSE SOUTH	WABAMUN	7	10/10	6	-	6	1090	7	
	LEDUC	1700	10/15	1300	150	1150	1090	1254	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED AND ALBERTA AND SOUTHERN GAS CO. LTD.
WESTLOCK	VIKING	310	15/5	250	9	241	1040	251	GAS SOLD TO CANADIAN INDUSTRIAL GAS LIMITED AND SUPPLIES LOCAL UTILITY.
	BASAL BLAIRMORE	4	20/5	3	-	3	1100	3	
WEST PRAIRIE	CADOTTE	18	10/5	15	-	15	1040	16	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	BLUESKY	6	10/5	5	-	5	990	5	
WHITELAW	GETHING	31	15/5	25	4	21	1020	21	SUPPLIES LOCAL UTILITY.
	TRIASSIC	33	20/5	25	-	25	1090	27	
WILDCAT HILLS	MISSISSIPPIAN	810	15/20	550	35	515	1080	556	GAS SOLD TO ALBERTA AND SOUTHERN GAS CO. LTD.
WILDHORSE CREEK	MISSISSIPPIAN	150	15/20	100	-	100	940	94	
WILDMERE	BLAIRMORE	22	20/5	17	8	9	960	9	SUPPLIES LOCAL UTILITY.
WILDUNN CREEK	VIKING	35	25/5	25	-	25	1010	25	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED.

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WILLESDEN GREEN	BELLY RIVER	4	20/5	3	-	3	1000	3	
	CARDIUM	12	20/5	9	-	9	1100	10	
	CARDIUM SOLUTION	250	75/35	40	-	40	1100	44	
	BASAL BLAIRMORE	20	10/15	15	-	15	1100	17	
WILLINGDON	VIKING	3	25/5	2	-	2	980	2	
	MANNVILLE	15	25/5	11	1	10	990	10	GAS SOLD TO WESTERN MINERALS LTD. PLANT AND SUPPLIES LOCAL UTILITY.
	LEDUC	11	10/5	9	4	5	990	5	
WILSON CREEK	PEKISKO	26	15/10	20	-	20	1090	22	FORMERLY CALLED BLINDMAN RIVER.
	BANFF	20	15/10	15	-	15	1080	16	
WIMBORNE	VIKING	1	25/5	1	-	1	1020	1	
	MISSISSIPPIAN	1	10/10	1	-	1	1100	1	
	NISKU	3	20/15	2	-	2	1160	2	
	NISKU SOLUTION	5	30/45	2	-	2	1160	2	
	LEDUC ASSOCIATED	320	10/30	200	-	200	1000	200	
	LEDUC SOLUTION	91	50/45	25	-	25	1000	25	
WINDFALL	VIKING	13	25/5	9	-	9	1030	9	
	MISSISSIPPIAN	5	15/5	4	-	4	1040	4	
	LEDUC	820	10/35	480	-	480	1050*	504	RESERVOIR BEING CYCLED. GAS SOLD TO ALBERTA AND SOUTHERN GAS CO. LTD. PRESSURE MAINTAINED BY PINE CREEK GAS.
WIZARD LAKE	VIKING	1	15/10	1	-	1	1070	1	
	BLAIRMORE	14	20/10	10	8	2	1120	2	GAS SOLD TO NORTHWESTERN UTILITIES, LIMITED.
	LEDUC SOLUTION	220	40/25	100	13	87	1250	109	
WOKING	PEACE RIVER	5	10/5	4	-	4	1040	4	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
	SPIRIT RIVER	3	20/5	2	-	2	1040	2	
	BLUESKY	4	20/5	3	-	3	1040	3	
	PERMO-PENN	3	20/5	2	-	2	1060	2	
	MISSISSIPPIAN	3	25/5	2	-	2	1070	2	

(1) FIELD OR AREA	(2) ZONE	(3) INITIAL GAS IN PLACE BCF	(4) LOSSES RESERVOIR/SURFACE PER CENT	(5) INITIAL MARKETABLE GAS BCF	(6) MARKETABLE GAS PRODUCED TO JUNE 30, 1964 BCF	(7) REMAINING MARKETABLE GAS TO JUNE 30, 1964 BCF	(8) ESTIMATED HEATING VALUE BTU PER CU. FT.	(9) REMAINING MARKETABLE GAS AT 1000 BTU PER CU.FT. BCF	(10) REMARKS
WOLF LAKE	CADOMIN	13	10/5	11	-	11	1060	12	PRESENTLY CONSIDERED BEYOND ECONOMIC REACH.
WOOD RIVER	BASAL BLAIRMORE	37	10/10	30	3	27	1090*	29	GAS SOLD TO TRANS-CANADA PIPE LINES LIMITED.
WORSLEY	LEDUC	270	15/5	220	21	199	1070	213	GAS SOLD TO WESTCOAST TRANSMISSION COMPANY LIMITED AND SUPPLIES LOCAL UTILITY.
WITHIN ECONOMIC REACH				36368	4093	32275		34058	
BEYOND ECONOMIC REACH				2454		2454		2549	
OTHER RESERVES	(WITHIN ECONOMIC REACH)			48		48		51	
LESS THAN 10 BCF	(BEYOND ECONOMIC REACH)			937		937		988	
TOTAL RESERVES, JUNE 30, 1964				39807	4093	35714		37646	

* MEASURED HIGHER HEATING VALUE.

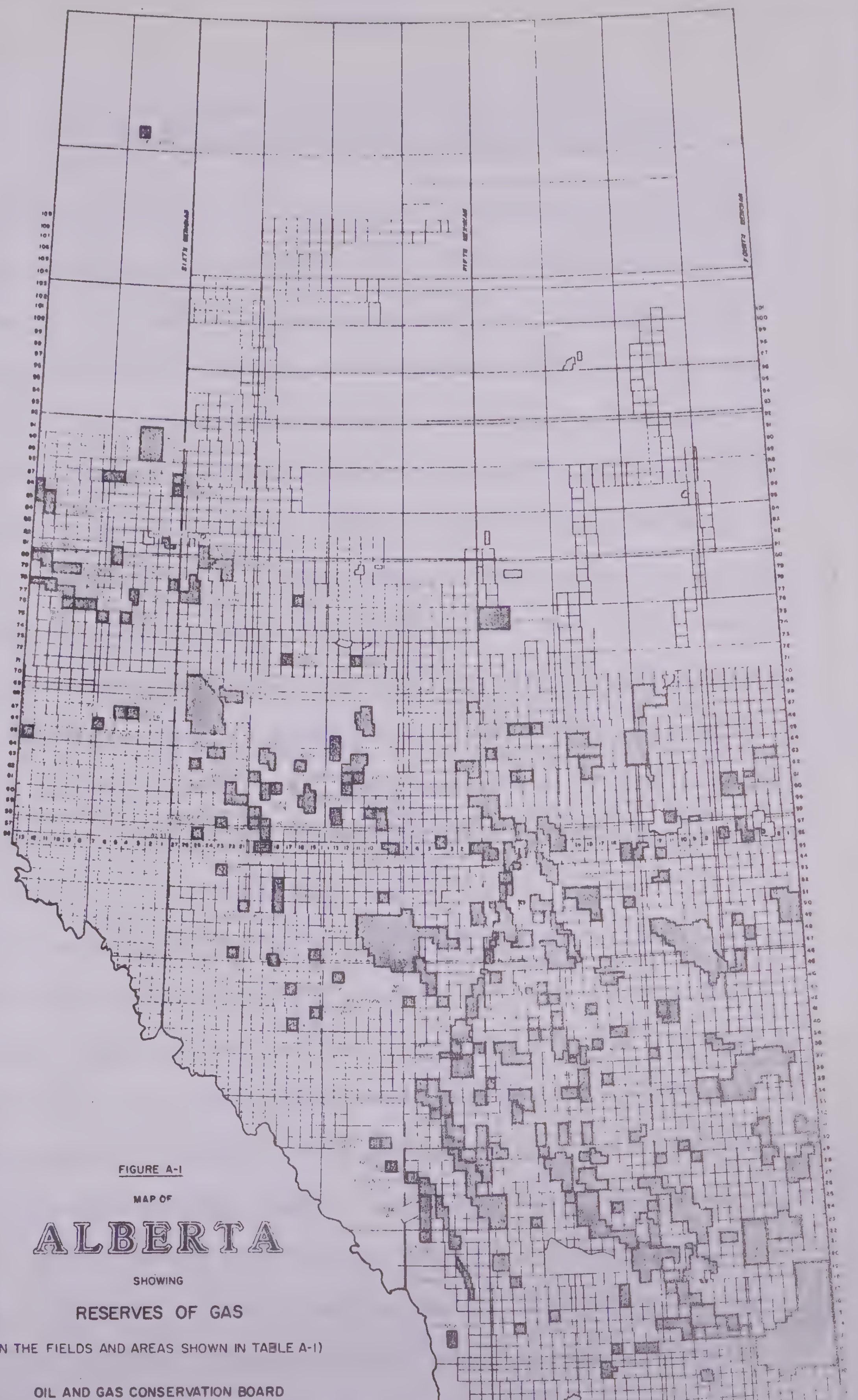

FIGURE A-1

MAP OF

ALBERTA

SHOWING

RESERVES OF GAS

(IN THE FIELDS AND AREAS SHOWN IN TABLE A-1)

OIL AND GAS CONSERVATION BOARD
603-6th AVENUE WEST
CALGARY, ALBERTA

APPENDIX B

THE TRENDS IN EXPLORATION FOR AND THE GROWTH OF RESERVES OF GAS IN ALBERTA

There are two general methods in common use by estimators in forecasting future reserves of oil or gas: the geological or volume of sediments method and the statistical method. The geological method as applied to gas reserves, involves determining the volume of available favourable sediments in a particular area. To this volume is then applied an estimated ratio of reserves to sediments based on the estimated gas reserves in relation to the volume of similar fully or nearly fully developed sediments elsewhere. The method is useful primarily in estimating the ultimate reserves that might be discovered underlying a relatively large area. Its reliability depends upon the validity of the comparison of the two areas. The matter of ultimate reserves will be discussed in greater detail later in this Appendix.

The statistical method of estimating future reserves consists of a historical analysis of the gas reserves discovered per exploratory well or exploratory foot drilled and the application of the trends indicated to an estimated ultimate number of exploratory wells or footage. This method is particularly useful for short range estimates and has been used extensively by the Board in recent years. The major portion of the trend evidence submitted at the recent hearings was concerned with this approach. Such evidence is summarized and discussed below.

Submission of Trans-Canada

Trans-Canada at the hearing of it's application did not present any new evidence regarding the trends in reserve growth in the Province, but did revise and extend tables V-3 and V-5 of the Board's Reserve Report of December 31, 1963 (OGCB Report 64-8) to reflect increased reserve estimates for those pools which have undergone significant development since that time. It accepted the Board's "appreciation factors" as presented in Figure V-4 of the above mentioned report, and on this basis adjusted its initial marketable reserve estimate of some 39.7 trillion cubic feet (as of April 1, 1964) to about 43.3 trillion cubic feet when fully appreciated.

The long term growth rate of initial marketable gas reserves due to both new discoveries and appreciation of known reserves, including the above mentioned April 1, 1964, estimate, was estimated by Trans-Canada to be 2.6 trillion cubic feet per year. Trans-Canada contended that since the cumulative fully appreciated reserve discovered per wildcat well drilled has remained at about 7.0 billion cubic feet over the last four years, it is likely that at the present rate of exploratory drilling this long term growth rate will be maintained.

Submission of Alberta and Southern

Mr. S. R. Blair presented a report entitled "Review of Statistics of Trends in the Growth of Gas Reserves in

Western Alberta" in support of the application of Alberta and Southern.

The area considered in the study is that portion of the Province west of the Fifth Meridian and south of Township 80. Reserve growth in this area was compared to the reserve growth for the Province as a whole as presented by the Board in its Reserve Report of December 31, 1963.

The Alberta and Southern submission showed that during the past ten years there has been an upward trend in the number of exploratory wells drilled per year in the study area and that on a cumulative basis to December 31, 1963, the fully appreciated reserves per exploratory well are 15.9 billion cubic feet in the study area as compared to about 6.2 billion cubic feet for the entire Province. It also showed that the reserve weighted average ultimate appreciation (referred to reserves one year from the date of discovery as 100 per cent) is about 350 per cent for the study area, compared to some 248 per cent as estimated by the Board for the Province as a whole.

Within the study area, three distinguishable periods in the trends of reserve increase have been indicated according to Alberta and Southern. The first trend from 1953 to about 1957 shows a marketable gas reserve increase averaging some 1.1 trillion cubic feet per year, whereas the next period from about 1958 to 1961 exhibits a significant increase in rate to 2.8 trillion cubic feet per year, followed by the third period from 1961 to the end of 1963 where the reserve increase rate declined to about 1.2 trillion cubic feet per year.

Alberta and Southern considered this analysis to demonstrate a correlation between gas reserve growth and incentive to develop, inasmuch as the greater rate of growth occurred during the period in which permittees were actively engaged in gas purchasing. In cross-examination, Mr. Chernoff of Alberta and Southern explained the reason for the decrease in reserve growth during the period, 1961 to 1963, as not caused by a decrease in exploratory effort but as a result of a sharp decline in development drilling and hence in appreciation actually realized in the area.

Alberta and Southern stated in his submission and Mr. Blair repeated in direct and cross-examination, that a reserve growth rate for the Province of some 2.5 trillion cubic feet per year could be counted on for several years into the future.

Submission of the Utilities Companies

The Utilities Companies did not present any direct evidence concerning the trends in gas reserve growth. They did, however, question the trends, as estimated by the applicants and the use of such trends as part of the supply to meet requirements. This matter is discussed in detail in Appendix D.

The Board's Analysis of the Trends in the Growth of Gas Reserves in Alberta

Effective January 1, 1964, the Board adopted the Lahee system of well classification utilized by the American Association of Petroleum Geologists and by the Alberta Society of Petroleum Geologists. The category of total exploratory wells, as used in this report, is comprised of

(a) new field wildcats,
(b) new pool wildcats,
(c) shallow pool tests, and
(d) deep pool tests.

While the Lahee system differs somewhat from the system previously used by the Board, from the point of view of reserves discovered per exploratory well there is very little difference between the figures calculated by the Lahee system and those calculated by the Board's old system. The annual drilling data, converted to the new basis, are included in Table B-1, and are presented graphically as Figure B-1 for the period, 1954 through 1964. There were 368 exploratory wells drilled from January 1 to September 30, 1964, and for purposes of completing Figure B-1, it has been estimated that a total of 500 exploratory wells will be drilled by the end of the year. Exploratory wells drilled to June 30, 1964, total 6,568. In the past, the Board has assumed an ultimate density of one exploratory well per 10 square miles of prospective area. This assumption has been reviewed in light of the adoption of the Lahee well classification system and the Board is satisfied the estimated ultimate density is reasonable. At such a density some 20,000, or more perhaps, exploratory wells (or some three times the current number) would eventually be drilled in Alberta.

The currently estimated initial marketable gas reserves, shown in Appendix A, are tabulated in Table B-1 by the year of pool discovery. In this table, the names of the major (10 billion cubic feet or over) pools and fields discovered each year are listed, together with the annual number of total exploratory wells and the initial marketable reserves (as estimated at June 30, 1964) attributed to each year's discoveries. Figure B-2 is a graphical presentation of these reserve data, together with the corresponding data from previous Board reserve reports. The spread between any two points for a particular year of discovery represents the amount of appreciation that has taken place from the date of the estimate represented by the lower point to the date represented by the upper point. The long term growth rate of initial marketable gas reserves due both to new discoveries and to appreciation of known reserves has been about 2.5 trillion cubic feet per year, as indicated by the dashed line on Figure B-2. This long term rate of growth has been essentially unchanged over the last few years, but the actual growth has varied considerably from year to year. (For the years 1959, 1960, 1961, 1962 and 1963 the growth in trillions of cubic feet has been 3.5, 3.5, 0.5, 1.7 and 1.3, respectively.

During the first half of 1964 the growth rate has been at some 6.2 trillion cubic feet per year.)

The exploratory drilling and initial marketable gas reserve data of Table B-1, together with the amount of marketable gas produced and the corresponding remaining reserves, are summarized on Table B-2 by year of discovery. The reserves per exploratory well drilled, calculated on an annual basis, are shown in column 8 of this table. These annual data are not comparable since for the early years the discoveries are fully appreciated whereas in recent years the degree of appreciation is considerably less. This is particularly true with respect to 1963 and 1964.

The appreciation of gas reserves in the years following discovery has been analysed as a means of estimating the future appreciation of recent discoveries. The method adopted involves determining the percentage increase in estimated initial gas reserves as a function of the elapsed time from an average date of discovery to the date of subsequent reserve determinations. Data for discoveries made in each of the years 1951 to 1962 inclusive, are plotted on Figure B-3. A review of these data did not suggest any change in the reserve weighted normal appreciation curve as shown in the Board's report of February, 1964. This curve is shown as a red line on the figure.

The current reserve estimates for each of the last seven years gas discoveries have been adjusted to appreciated values using the normal appreciation curve of Figure B-3. The appreciation factors used and the corresponding adjusted reserves are presented in Table B-3. Initial gas reserves, now estimated to total 39.8 trillion cubic feet, are expected to appreciate by over three trillion cubic feet to 43.2 trillion cubic feet. The fully appreciated gas reserves per exploratory well are shown in column 7 of Table B-3.

Both the currently established and the appreciated reserves per exploratory well are plotted for the period, 1954 to June 30, 1964, in Figure B-4. The appropriate data from column 8 of Table B-2 were used for the current ratio of reserves per exploratory well and from column 7 of Table B-3 for the appreciated values. The figure shows that the fully appreciated reserves developed per exploratory well have, on a cumulative basis, declined from over 8 billion cubic feet per well in 1954 to about seven billion cubic feet per well in 1964. On an annual basis, the ratio has varied considerably from year to year but the running average has been in the order of 4 to 5 billion cubic feet per well for the last six or seven years.

Ultimate Reserves

At the hearing of the application of Alberta and Southern, both the CPA and British American submitted evidence regarding ultimate reserves.

CPA stated in its submission that 60 to 75 per cent of the reserves of the Province have yet to be found. During cross-examination, the witness stated that these percentages referred to reserves in excess of the 35.5 trillion cubic feet of recoverable gas which, according to the Association, had been discovered in Alberta to the end of 1963. On this basis, it would appear that the CPA's estimate of ultimate reserves ranges between 90 and 140 trillion cubic feet. However, the witness indicated that his committee placed more weight on a rounded maximum of 150 trillion cubic feet. The witness mentioned that this maximum estimate was based on a re-assessment and confirmation of an estimate made by the CPA during 1958 for the Borden Royal Commission on Energy and another estimate made later in the same year for the National Energy Board. The first estimate pertained to the entire sedimentary area of Western Canada, for which an ultimate reserve of 300 trillion cubic feet was calculated on the premise that as much recoverable gas per cubic mile has been trapped in the sediments of Western Canada as has been estimated, on a conservative basis, to have been trapped in the sediments of the United States. The second estimate involved an assessment of how much of Western Canada's 300 trillion cubic feet of ultimate reserves should be allocated to Alberta. In proportion to sedimentary volumes, Alberta's share would be less than 110 trillion cubic feet. However, on the basis of the success encountered to date in Alberta relative to the remainder of Western Canada, the committee saw fit to increase its estimate of Alberta's ultimate reserves from 110 to 150 trillion cubic feet. The witness further testified that the estimate of 150 trillion cubic feet appeared reasonable when Alberta was compared with the more thoroughly developed and geologically similar Mid-Continent area of the United States. By applying the presently proved accumulation factor (discovered gas reserves per cubic mile) of the Mid-Continent area to Alberta, an ultimate Alberta reserve of 110 trillion cubic feet was calculated. On the basis that the accumulation factor of the Mid-Continent area will increase further, for exploration is continuing in that area, it was estimated that an ultimate reserve of 150 trillion cubic feet could be reasonably expected in Alberta.

The British American submission stated that the potential gas reserves of the Province are in the order of 150 trillion cubic feet. This estimate was based on a detailed British American study in which each geological system was separately analysed as to its ultimate reserve potential. This estimate is understood to include some reserves that will not be economic to recover. British American considered its study confidential and did not submit it as an exhibit at the hearing.

The Board recognizes that any estimate of the ultimate reserves of the Province is, at best, only an indication of the order of magnitude. This is borne out by the wide variations in recent estimates made for the United States, where the minimum estimates are about one-third of the maximum estimates in spite of the fact that the United States has been more thoroughly explored than Alberta.

The Board's staff estimate that the Province of Alberta is underlain by some 280,000 cubic miles of sediment favourable to the entrapment of gas. Estimates of an accumulation factor based on an estimated ratio of ultimate gas reserves to sediments in the United States vary from about 0.25 to 0.75 billion cubic feet of gas per cubic mile of sediment. If a factor in the range of 0.3 to 0.4 is used, this results in an estimate of ultimate gas reserves of some 84 to 112 trillion cubic feet for the Province. The reasonableness of this range has been tested through an extrapolation of the long term trend of reserves per exploratory well to the ultimate number of wells expected.

Having regard to this estimate, and to evidence submitted at the recent hearings, the Board now believes that the figure it reported in its reserve report of December 31, 1963, of some 60 to 80 trillion cubic feet is on the low side. The Board believes that an estimated ultimate reserve for the Province of approximately 100 trillion cubic feet is reasonable.

TABLE B-1

TRENDS IN EXPLORATORY DRILLING AND GROWTH OF MARKETABLE GAS RESERVES IN ALBERTA

YEAR	EXPLORATORY WELLS DRILLED		MAJOR GAS RESERVES DISCOVERED	INITIAL MARKETABLE RESERVES	
	ANNUAL	CUMULATIVE		ANNUAL BCF	CUMULATIVE BCF
Prior to 1931			Bow Island, Brooks, Foremost, Medicine Hat (Medicine Hat, Bow Island), Pouce Coupe, Turner Valley (Mississippian Associated), Viking-Kinsella (Viking), and Wainwright.	3,138	3,138
1931 to 1940			Aden (Bow Island, Basal Colorado, Mississippian), Bantry, Lloydminster, Princess, Turner Valley (Mississippian Solution), Wildmere, and one small pool.	695	3,833
1941 to 1945			Black Butte (Bow Island, Sunburst-Ellis, Mississippian), Jumping Pound, Oyen (Viking), Suffield (Milk River), and four small pools.	689	4,522
1946		484(E)	Beaverhill Lake-Fort Saskatchewan (Viking), Brooks North-east (Mannville), Lindbergh, Pendant d'Oreille (Bow Island), and Provost.	1,228	5,750
1947	71	555	Fairydell-Bon Accord, Leduc-Woodbend, Manyberries, Medicine Hat (Ellis), Smith Coulee, and three small pools.	758	6,508
1948	124	679	Brooks North-east (Bow Island), Morinville, Pincher Creek, Redwater, and four small pools.	1,096	7,604

YEAR	EXPLORATORY WELLS DRILLED		MAJOR GAS RESERVES DISCOVERED	INITIAL MARKETABLE RESERVES	
	ANNUAL	CUMULATIVE		ANNUAL BCF	CUMULATIVE BCF
1949	212	891	Acheson East, Bollogque Lake, Boyle-Mustang-Amisk Lake, Campbell-Namao, Castor, Cessford, Excelsior, Golden Spike, Inland, Joarcam, Lac La Biche, Normandville (Gething), Plain Lake, Rochester, Stettler, Westlock (Viking), Willingdon, and eleven small pools.	2,188	9,792
1950	210	1,101	Acheson, Countess (Bow Island), Drumheller (Blairmore), Fenn-Big Valley, Jarvie, Rolling Hills (Bow Island), Sibbald, Whitelaw, and seventeen small pools.	399	10,191
1951	346	1,447	Atlee-Buffalo (Bow Island), Bashaw (Leduc Associated), Belloy (Gething, Mississippian), Bonnie Glen, Clive, Countess (Basal Colorado), Etzikom (Bow Island), Figure Lake, Glen Park, Hamelin Creek, Majeau Lake, Millet, Okotoks, Tangent, Viking-Kinsella (Blairmore, Devonian), Wizard Lake, and nineteen small pools.	1,484	11,675
1952	442	1,889	Alix, Bindloss (Viking), Bittern Lake, Chigwell, Comrey (Bow Island), Dixonville, Eaglesham (Mississippian), Erskine, Gordondale (Paddy), Hackett, Hairy Hill, Hamilton Lake, Hercules, Holmberg, Hussar (Blairmore), Minnehik-Buck Lake, Nevis, Olds, Phil Can, Rycroft, St. Albert-Big Lake, St. Brides, West Drumheller, Westerose, Wildunn Creek, and twenty-four small pools.	3,003	14,678
1953	338	2,227	Atlee-Buffalo (Basal Blairmore), Donalda (Viking, Detrital), Dyberg, Enchant, Eyremore, Gilby (Viking, Jurassic), Gordondale (Notikewin,		

YEAR	EXPLORATORY WELLS DRILLED		MAJOR GAS RESERVES DISCOVERED	INITIAL MARKETABLE RESERVES	
	ANNUAL	CUMULATIVE		ANNUAL BCF	CUMULATIVE BCF
1953 (cont)			Gething), Homeglen-Rimbey, Kessler (Viking), Kneller, Parkland North-east, Pembina (Cardium Solution), Pouce Coupe South (Peace River), Rich, Samson, Sedalia, Steen River, Sturgeon Lake South (Gething, Leduc), Sturgeon Lake South General Area (Gething, Permo-Penn), Sylvan Lake (Blairmore, Mississippian), Three Hills Creek (Viking, Mississippian), Usona, Waterglen, Wayne-Rosedale (Viking, Blairmore), Westerose South (Leduc), Wood River, and seventeen small pools.	4,644	19,322
1954	368	2,595	Alexander, Bellshill Lake (Viking, Blairmore), Bindloss (Basal Blairmore), Braeburn, Countess (Blairmore), Crossfield (Wabamun), Garrington (Leduc), Ghost Pine (Blairmore), Gilby (Basal Blairmore, Mississippian, Banff, Wabamun), Harmattan-Elkton (Mississippian Associated), Hespero (Blairmore, Leduc Associated), Holborne, Hussar (Viking), Pembina (Belly River), Saddle Hills (Peace River, Gething), Sarcee, Savanna Creek, Turin (Bow Island, Basal Blairmore), Willesden Green (Cardium Solution), Wimborne (Viking, Leduc), and thirteen small pools.	3,332	22,654
1955	351	2,946	Aden (Sunburst-Ellis), Burnt River, Carbon (Blairmore), Chinook Ridge, Control, Harmattan-Elkton (Mississippian Solution), Lone Pine Creek (Wabamun), Pakowki Lake, Red Willow (Viking), Richdale, Rolling Hills (Basal Colorado), Sundre (Mississippian Associated and Solution), Windfall (Viking, Leduc), and nineteen small pools.	1,081	23,735

YEAR	EXPLORATORY WELLS DRILLED		MAJOR GAS RESERVES DISCOVERED	INITIAL MARKETABLE RESERVES	
	ANNUAL	CUMULATIVE		ANNUAL BCF	CUMULATIVE BCF
1956	373	3,319	Alderson (Second White Specks), Beaver Creek, Connorsville, Crossfield (Cardium Solution, Mississippian), Eaglesham (Gething, Cadomin), Esther, Goodwin Lake, Harmattan East (Mississippian Associated), Hussar (Basal Colorado), Innisfail (Mississippian, Wabamun), Joffre (Nisku Solution), Kirkcaldy (Basal Mannville), Mazeppa, Medicine River (Jurassic Solution), Mountain Park, Normandville (Triassic, Mississippian), Obed, Paddle River, Pembina (Viking, Mississippian), Pine Creek (Wabamun), Standard, Steep Creek (Gething, Triassic), Two Creek, Waterton (Mississippian), West Prairie, and thirty-two small pools.	4,544	28,279
1957	452	3,771	Antelope, Blueridge, Carson Creek, Chisholm, Crossfield (Basal Blairmore), Esther (Banff), Faust South, Garrington (Viking, Blairmore), Harmattan East (Mississippian Solution), Harmattan-Elkton (Mississippian Non-Associated), Innisfail (Leduc), Joffre (Viking, Basal Blairmore), Kaybob (Notikewin, Cadomin, Winterburn, Beaverhill Lake), Lambert Creek, Lovett River (Rundle), Pembina (Blairmore, Nordegg), Pine Creek (Leduc), Saddle Hills (Permo-Penn), Stolberg, Swan Hills (Beaverhill Lake Solution), Virginia Hills (Blairmore, Beaverhill Lake Solution, Slave Point), and twenty-four small pools.	2,392	30,671
1958	428	4,199	Berland River, Berland River West, Boundary Lake South, Caroline, Carson Creek North, Carstairs (Mississippian), Clear Hills, Fox Creek West (Nisku), Gilby (Jurassic Solution), Greencourt (Jurassic-Detrital), Penhold, Pouce Coupe South (Gething), Prevo, Simonette (Leduc), Steep Creek (Permo-Penn), Waterton (Devonian), Wildcat Hills, Woking, and twenty-four small pools.	2,326	32,997

YEAR	EXPLORATORY WELLS DRILLED ANNUAL	EXPLORATORY WELLS DRILLED CUMULATIVE	MAJOR GAS RESERVES DISCOVERED	INITIAL MARKETABLE RESERVES ANNUAL BCF	INITIAL MARKETABLE RESERVES CUMULATIVE BCF
1959	438	4,637	Bigorary (Mississippian), Bigstone (Dunvegan), Brazeau River, Burnt Timber, Garrington (Mississippian), Judy Creek, Lookout Butte, Lovett River (Blairmore), Medicine River (Blairmore, Jurassic Associated), Retlaw (Bow Island, Basal Blairmore), Simonette (Wabamun), Waskahigan, Worsley, and twenty-three small pools.	1,603	34,600
1960	412	5,049	Bigorary (Blairmore), Bigstone (Gething, Leduc), Black Butte (Basal (Colorado), Brown Creek, Carson Lake, Crossfield East (Mississippian), Kaybob (Gething), Kaybob South (Viking), Kirkcaldy (Mississippian), Moose Mountain, Nordegg, Redland (Blairmore), Rowley (Viking, Mississippian), Sieu River, Simonette (Cadomin), Sturgeon Lake South General Area (Cadomin), Sylvan Lake (Mississippian Solution), Wildhorse Creek, Willesden Green (Basal Blairmore), Wilson Creek (Mississippian), Wolf Lake, and thirty-six small pools.	1,004	35,604
1961	395	5,444	Benjamin Creek (Mississippian), Craigend, Crossfield East (Wabamun), Greencourt (Mississippian), Harmattan-Elkton (Leduc), Jumping Pound West (Mississippian), Kaybob South (Cadomin, Nisku, Beaverhill Lake), Marten Hills (Wabiskaw, Wabamun), Pendant d'Oreille (Mannville), Plover Lake (Viking), Sylvan Lake (Leduc), Twining North (Mississippian), Verger (Basal Mannville), Wilson Creek (Banff), and fifteen small pools	2,066	37,670
1962	433	5,877	Bashaw (Blairmore), Carbon (Mississippian), Edson (Mississippian), Hunter Valley, Kaybob South (Triassic), Strathmore, Sylvan Lake (Jurassic), Twining		

YEAR	EXPLORATORY WELLS DRILLED		MAJOR GAS RESERVES DISCOVERED	INITIAL MARKETABLE RESERVES	
	ANNUAL	CUMULATIVE		ANNUAL BCF	CUMULATIVE BCF
1962 (cont)			(Mississippian Non-Associated), Virginia Hills (Triassic), and seventeen small pools.	1,768	39,438
1963	424	6,301	Edson (Gething), Medicine River (Mississippian Non-Associated), Pine North-west (Leduc), Swalwell (Mississippian), and twenty-five small pools.	226	39,664
1964	267	6,568	Gold Creek (Wabamun), Marsh Head Creek (Leduc), Smoky River (Wabamun), and Twenty-three small pools.	143	39,807

TABLE B-2

TRENDS IN EXPLORATORY DRILLING AND IN THE DISCOVERY OF INITIAL MARKETABLE GAS RESERVES

(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
	EXPLORATORY WELLS DRILLED(1)		MARKETABLE GAS RESERVES AS OF JUNE 30, 1964 BILLIONS OF CUBIC FEET				GAS RESERVES PER EXPLORATORY WELL BCF/WELL
DISCOVERY YEAR	ANNUAL	CUMULATIVE	INITIAL	PRODUCED	REMAINING	CUMULATIVE INITIAL	ANNUAL
PRIOR TO 1947		484 (2)	5750	1787	3963	5750	
1947	71	555	758	171	587	6508	10.7
1948	124	679	1096	216	880	7604	8.8
1949	212	891	2188	232	1956	9792	10.3
1950	210	1101	399	41	358	10191	1.9
1951	346	1447	1484	173	1311	11675	4.3
1952	442	1889	3003	302	2701	14678	6.8
1953	338	2227	4644	526	4118	19322	13.7
1954	368	2595	3332	162	3170	22654	9.1
1955	351	2946	1081	23	1058	23735	3.1
1956	373	3319	4544	149	4395	28279	12.2
1957	452	3771	2392	117	2275	30671	5.3
1958	428	4199	2326	160	2166	32997	5.4
1959	438	4637	1603	24	1579	34600	3.7
1960	412	5049	1004	4	1000	35604	2.4
1961	395	5444	2066	6	2060	37670	5.2
1962	433	5877	1768	-	1768	39438	4.1
1963	424	6301	226	-	226	39664	0.5
JUNE 30, 1964	267	6568	143	-	143	39807	0.5

(1) EXPLORATORY WELLS BASED ON THE LAHEE SYSTEM.

(2) ESTIMATED.

TABLE B-3

ANTICIPATED APPRECIATION OF GAS RESERVES AND CORRESPONDING ADJUSTED RESERVES PER EXPLORATORY WELL

(1)	(2)	(3)	(4)	(5)	(6)	(7)
	INITIAL MARKETABLE RESERVES AS OF JUNE 30, 1964	AVERAGE DISCOVERY DATE TO JUNE 30, 1964		ULTIMATE INITIAL MARKETABLE RESERVES BILLIONS OF CUBIC FEET		ADJUSTED GAS RESERVES PER EXPLORATORY WELL BCF/WELL
DISCOVERY YEAR	BCF	YEARS	APPRECIATION FACTOR	ANNUAL	CUMULATIVE	ANNUAL
PRIOR TO 1957	28279	8.0	1.00		28279	
1957	2392	7.0	1.00	2392	30671	5.3
1958	2326	6.0	1.01	2349	33020	5.5
1959	1603	5.0	1.05	1683	34703	3.8
1960	1004	4.0	1.13	1135	35838	2.8
1961	2066	3.0	1.32	2727	38565	6.9
1962	1768	2.0	1.65	2917	41482	6.7
1963	226	1.0	2.49	563	42045	1.3
JANUARY TO JUNE 30, 1964	143	0.25	8 (1)	1144	43189	4.3 (1)

(1) ESTIMATED

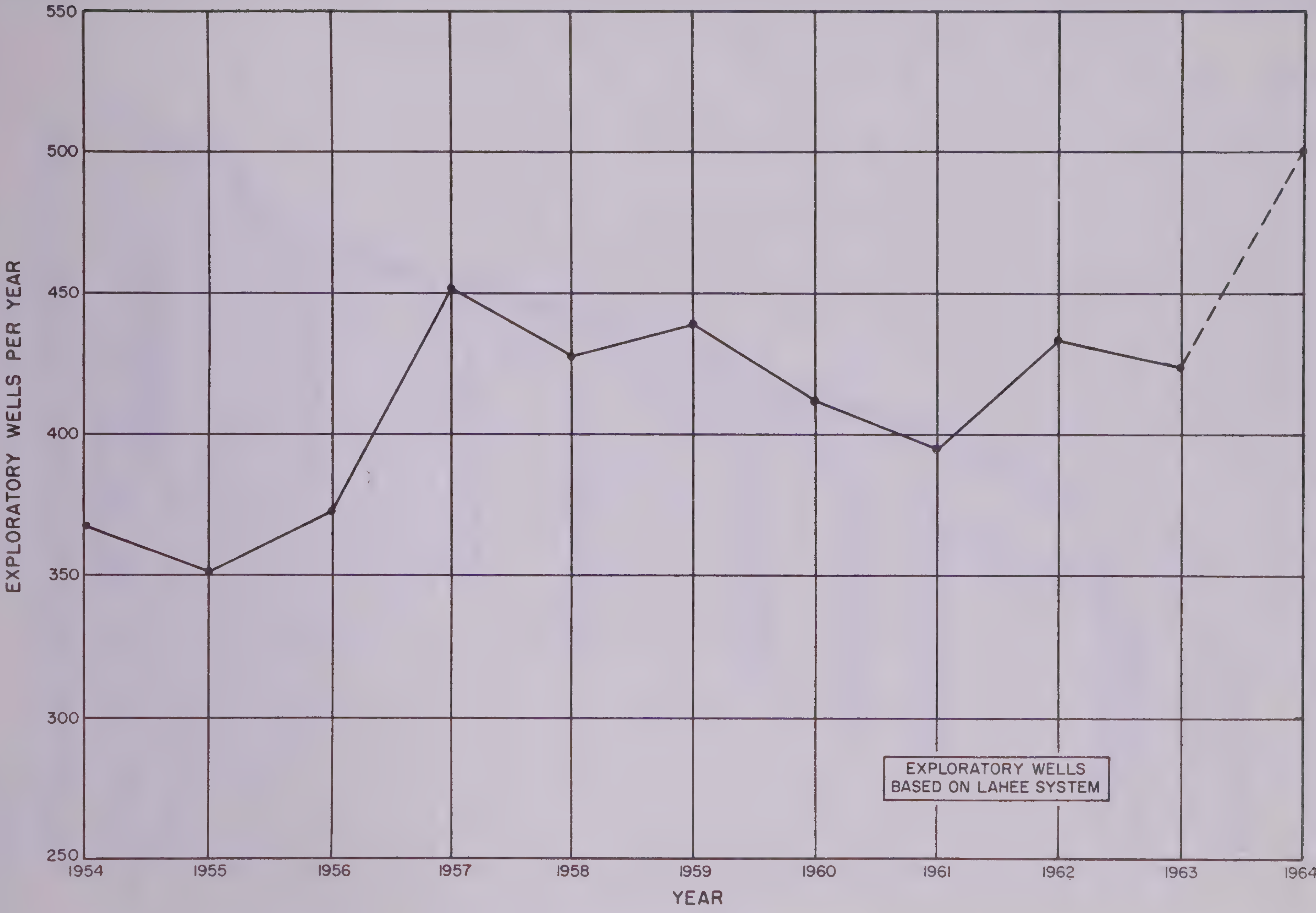

FIGURE B-1 — TRENDS IN EXPLORATORY DRILLING

OIL AND GAS CONSERVATION BOARD
CALGARY, ALBERTA NOVEMBER, 1964

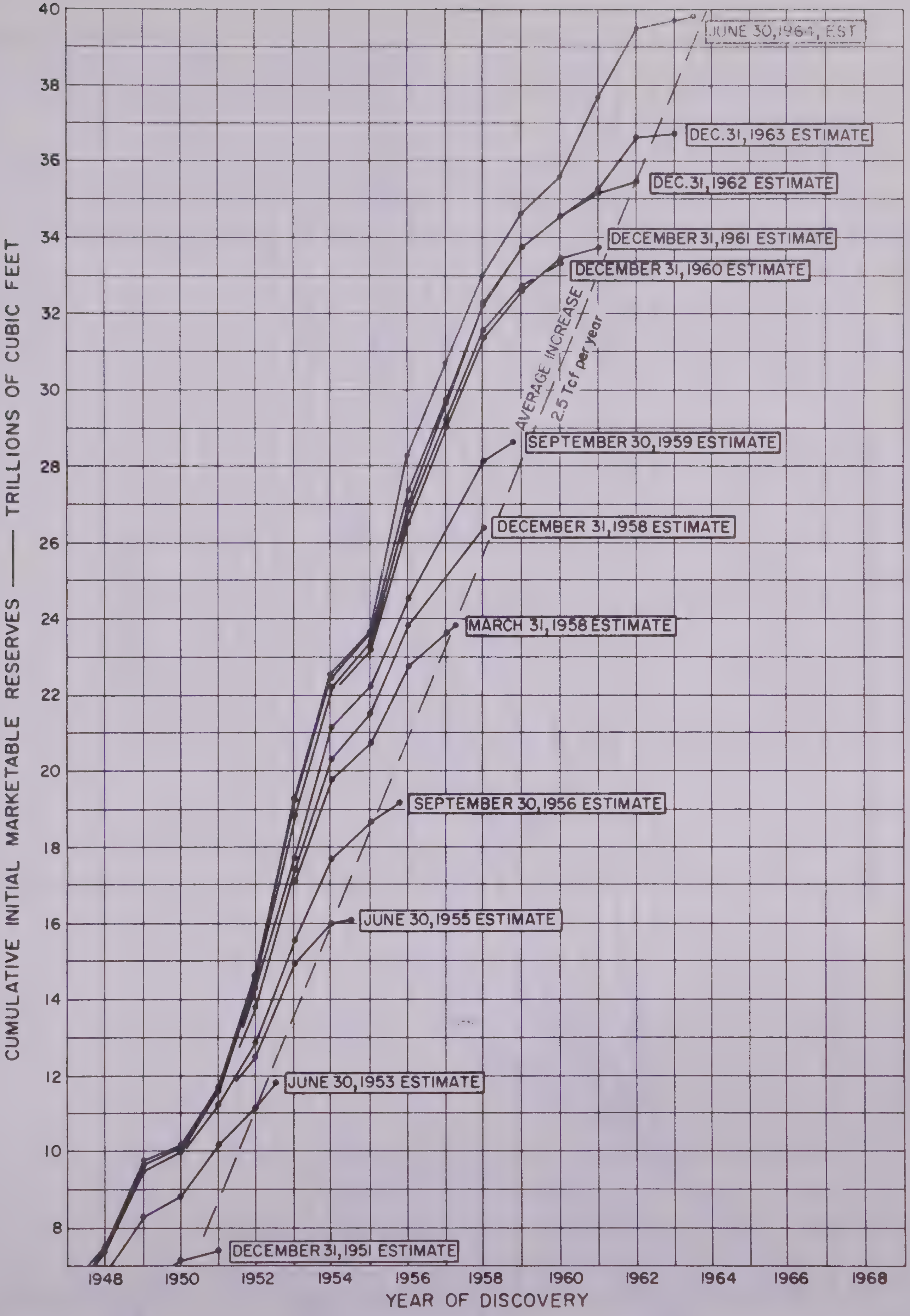

FIGURE B-2 GROWTH OF INITIAL MARKETABLE GAS RESERVES

OIL AND GAS CONSERVATION BOARD
CALGARY, ALBERTA NOVEMBER, 1964

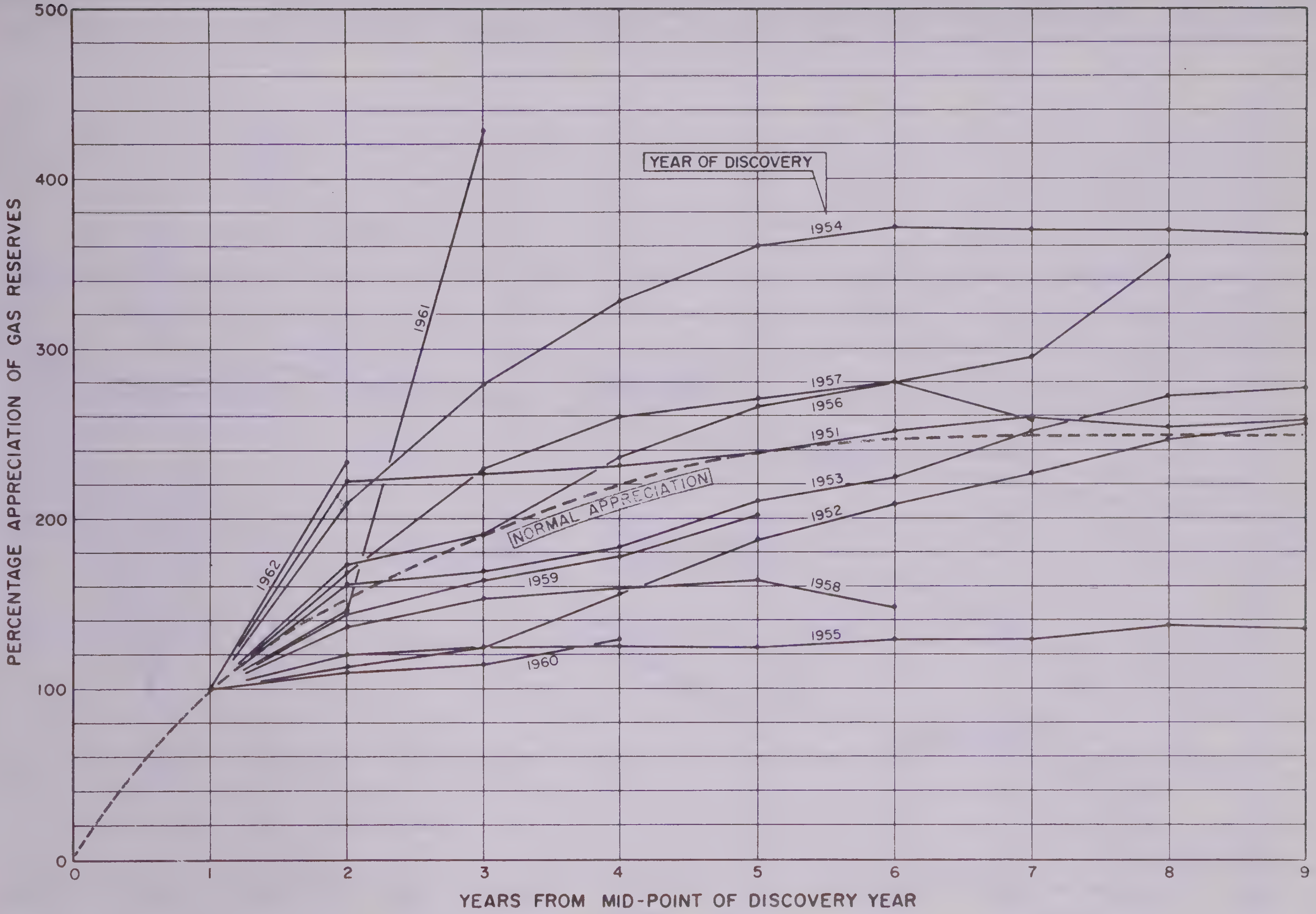

FIGURE B-3 PERCENTAGE APPRECIATION OF GAS RESERVES REFERRED TO RESERVES ONE YEAR FROM DATE OF DISCOVERY

OIL AND GAS CONSERVATION BOARD
CALGARY, ALBERTA NOVEMBER, 1964

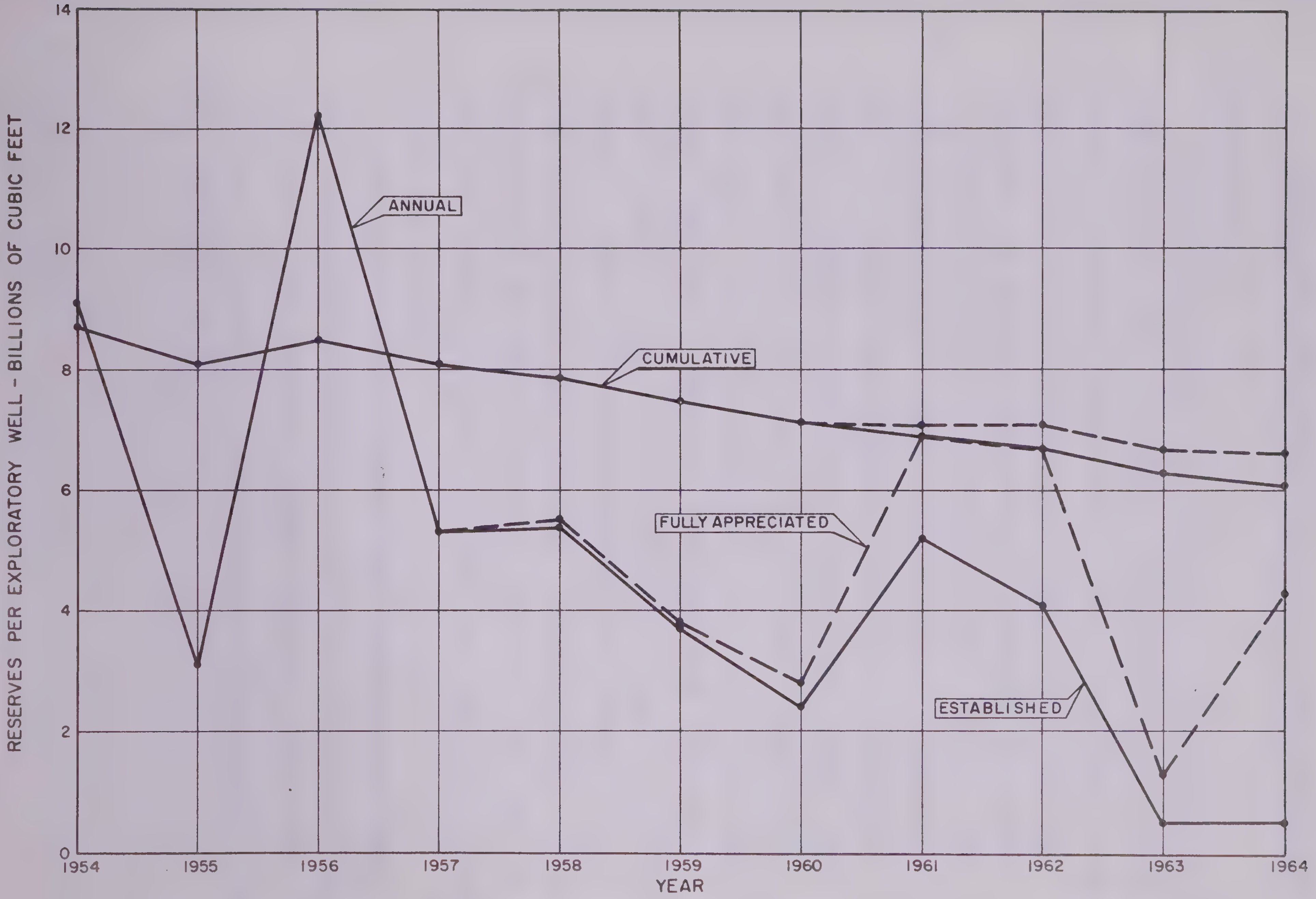

FIGURE B-4 — TRENDS IN THE DISCOVERY OF GAS RESERVES PER EXPLORATORY WELL

OIL AND GAS CONSERVATION BOARD
CALGARY, ALBERTA NOVEMBER, 964

APPENDIX C

ALBERTA GAS REQUIREMENTS AND PRESENT PERMIT COMMITMENTS

Introduction

The extensive evidence submitted by the Utilities Companies formed the major part of evidence led concerning future demand for gas in Alberta. The applicants and those producer interveners who indicated support of the applications tended to agree with the Board's forecasts of the overall thirty-year requirements as stated in its February, 1964 report on the Trans-Canada application heard by the Board on September 23, 1963.(1) The Utilities Companies submitted an independent forecast, indicating requirements considerably greater than those forecast by the Board. The Utilities Companies were supported in a general way by the City of Calgary and Sherritt Gordon. The City of Edmonton, which also took a generally similar position, stated in its submission that if industrial expansion continued the requirements of the Province would be considerably more than the Board's February, 1964, estimate. However, Mayor Hawrelak, witness for the City, said that the City didn't doubt the Board's estimate, but wanted to be sure that it was optimistic.

Both Trans-Canada and Alberta and Southern stated that they had not made independent surveys of gas requirements for the Province, but indicated agreement with the thirty-year requirements of 8.74 trillion cubic feet(2) estimated by the Board in its February, 1964, report. On questioning, both applicants stated that they believed the Board figure to include plant shrinkage during gas processing at Pacific's Empress extraction plant, and the compressor fuel requirements of the Alberta Gas Trunk Line.

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(1) OGCB Report 64-1.

In evidence given in rebuttal, Mr. S. R. Blair of Alberta and Southern introduced a graph depicting forecasts of gas demand for Alberta made in the past by the Utilities Companies, the National Energy Board, the Stanford Research Institute and the Oil and Gas Conservation Board, comparing them with actual sales to 1963, and the submitted forecast of the Utilities Companies. The graph showed that a forecast made in 1957 by Stanford for the two Utilities Companies had shown a high degree of accuracy as compared with actual results. Mr. Blair urged that the Board give particular weight to the forecast in view of its accuracy, although it was projected to 1970 only, reaching an annual rate of about 220 billion cubic feet or some 20 billion cubic feet less than the Utilities Companies' forecast for that year.

Utilities Companies' Forecast

Northwestern Utilities, Limited and Canadian Western

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(2) The Board forecast of 8.74 trillion cubic feet, published in Report 64-1, did not make provision for gas processing shrinkage at Empress and Alberta Gas Trunk Line fuel requirements. These items were included in the permit commitments.

Natural Gas Company Limited submitted a joint forecast of future requirements for the Province by three categories of demand: residential, commercial and industrial. The industrial requirements were divided further into 'basic industrial', 'special industrial' and 'contingency'. The forecasts were made in detail for each of the Utilities Companies' own service areas, and by the application of average rates of growth for other areas of the Province.

To determine requirements for the Northwestern and Canadian Western service areas, population estimates were made for each area by making a straight line extrapolation of past population growth equivalent to an average annual rate of 2.85 per cent for the Canadian Western service area and 2.78 per cent for the Northwestern area. Per capita requirements based on past trends were projected for the thirty-year period. Future volumes of sales for each of three categories of requirements, residential, commercial and basic industrial, were made by applying the population estimates to per capita requirements.

Separate provision was made for sales to specific large industrial customers, designated as 'special industrial'. For the Canadian Western service area, this provided for growth in the requirements of the four large industrial plants then being served. For the Edmonton area, special industrial requirements were those of ten large plants. With the exception of variations in the requirements of four of the plants during the early years of the forecast period and that of the Edmonton Power Plant, special industrial requirements for the Edmonton area were held constant at the 1963 level of sales. The variations allowed for the four plants were based on other information, presumably from the individual companies concerned, and that for the Edmonton Power Plant on a company projection.

A contingency industrial allowance was made to provide for new large industrial customers and unforeseen growth in the existing special industrial category. The levels of the contingency allowance of 2 billion cubic feet for Northwestern and 1 billion cubic feet for Canadian Western, beginning in 1966 and accumulated annually, were chosen so as to maintain slightly increasing per capita industrial sales throughout the period. Excluding the contingency allowance, projected per capita industrial sales for the two areas showed a marked decline.

As the two Utilities Companies had not previously made specific forecasts of requirements for the remainder of the Province, they consulted the Board staff prior to the hearings. Data for present demand obtained from the Board staff for areas other than those served by the Utilities Companies were used as a basis for estimating amounts to be added to the Utilities Companies' own requirements. The Utilities Companies believed that the rates of growth of 2.76 per cent and 2.69 per cent for both residential and commercial sales in the

Northwestern and Canadian Western areas respectively would represent realistic future rates of growth for these two categories in the remainder of the Province, excluding the Peace River region, as these growth rates essentially reflected the expected rate of population growth. Industrial demand was projected at a rate of 3.75 per cent, arbitrarily lower than the 4.27 per cent used for the Utilities Companies' service areas. They believed that the natural advantages of the metropolitan areas for industrial location would indicate a lesser rate of industrial growth in areas removed from them.

Requirements in the Peace River region were projected at a 5 per cent average annual growth rate, based on the experience of Northland Utilities Limited. In addition, a special allowance of 780 billion cubic feet, taken from OGCB Report 64-1, February, 1964, was added for prospective iron ore processing in the area. In evidence, Mr. Snyder stated that no allowance had been made in the Utilities Companies' forecast for shrinkage at the Empress extraction plant and the fuel requirement of the Alberta Gas Trunk Line. As Mr. Snyder, being questioned, agreed with the Board staff estimate of these requirements, they have been added to the Utilities Companies' estimates for purposes of comparison.

The requirements as estimated by Canadian Western and Northwestern are summarized in Table C-1.

In general, most of those giving evidence found the projections of residential and commercial requirements made by the Utilities Companies acceptable. Mr. Blair, however, in rebuttal evidence at the Alberta and Southern hearing, considered the basis of estimating requirements for areas other than the Edmonton and Calgary regions unduly optimistic. He considered that it would be more realistic to assume growth in the generally rural and small urban areas of the Province would be less than that for the metropolitan areas of Edmonton and Calgary. Earlier during the hearing, Mr. Willson had stated that he believed some areas were growing at a rate greater than that for Edmonton and Calgary, citing Red Deer as an example. He agreed, however, that Red Deer was served by the Northwestern Utilities system, and thus evidence of its growth was not relevant to growth outside the Utilities Companies' systems. In cross examination, CPA, IPAC and Shell, submitting testimony in support of the applications, stated that they considered the Utilities Companies' forecast unduly high. Mr. Z. P. Pokrupa, as a witness for Shell, stated that although he agreed with the residential and commercial requirements as estimated by the Utilities Companies, he found their projections of industrial demand quite unacceptable.

Considerable debate centred on the level of the contingency allowance provided in the Utilities Companies' forecast. Mr. Snyder testified that the level of the contingency was thought reasonable in view of the natural advantages for industrial location in the Edmonton and Calgary areas, and the low level of industrial saturation, especially in the Calgary area. Mr.

Snyder stated that whereas the average rate of industrial gas demand relative to the total was 50.5 per cent in the United states, 52.1 per cent in Canada and 52.0 per cent for Alberta as a whole, in the Canadian Western system it was only 34.1 per cent and in the Northwestern system, 38.9 per cent. The contingency allowance increased the rate to 41.9 per cent for the Canadian Western area by 1993, and 51.5 per cent in the Northwestern area, still less than the present average for the Province. Furthermore, Mr. Willson pointed out that, if the Shell scheme for development of the Athabasca oil sands should materialize, some 48 million cubic feet per day of natural gas would be required in its processing plant at Edmonton. This would absorb almost one-half of the total industrial contingency provided in the forecast of requirements for the Northwestern service area.

Excepting that of the city interveners and Sherritt-Gordon, most of the evidence disputed the high rate of industrial contingency allowed in the Utilities Companies' submission. The producer interveners and the applicants almost unanimously denied the Utilities Companies' contentions both that cheap and abundant gas was a prime reason for past industrial growth in Alberta and that the continuing availability of such gas was a sound reason for projecting a continued high level of growth. Mr. Pokrupa, as a witness for Shell, quoted a Stanford Research Institute study which stated that fuel was the least important factor in industrial location. Similarly, Mr. Strand of British American suggested that fuel costs were a very minor consideration in location decisions, with the exception of those for the petrochemical industry. He suggested also that the high rate of industrial growth during the last ten or fifteen years was related to the oil and gas industry rather than general manufacturing. Mr. Strand was of the opinion, supported almost unanimously by the other producer interveners, that future industrial growth will depend almost entirely on the expansion of the Province's population.

Mr. Snyder, on the other hand, suggested it was reasonable to assume future industrial growth would follow the trend of the past if gas remained available at reasonable and stable prices. He was, in a general way, supported by the evidence of Sherritt-Gordon, who invested the availability of cheap fuel with more importance in the location decision than did the producers and the applicants. Further support of this view was given by the cities of Edmonton and Calgary, who contended that stable supplies of gas at low prices would provide an incentive for industrial location. The two cities contended that further removal of gas from the Province would exert an upward pressure on prices and destroy the main advantage of their areas in the attraction of industry.

Board Staff Forecast

In view of the extent of the interest indicated prior to the two hearings, the Board staff made a complete review of its forecast of gas requirements for the thirty years, 1964 to 1993. As a prerequisite to making a forecast of domestic and commercial demand for natural gas, a forecast of population was made, followed by an estimation of the future trend in the rate of household formation.

Forecast of Alberta Population. A forecast of population growth in Alberta was made by census division. Data from the censuses of 1951, 1956 and 1961 were analysed to determine the changing characteristics of each census division according to family size, age distribution, and the rural-urban distribution of the population. Similarly, the growth rates of individual urban communities and rural districts were determined. Growth rates for each census division were developed by relating these two sets of data. The pattern of economic development in the Province was examined and related to each census division. The growth rates determined for each census division were then adjusted according to the influence expected patterns of economic development in each division would tend to exert on population trends. The growth factor determined for each division was applied to the 1961 census count, and the total for each division summed to obtain the Alberta total, resulting in an average annual growth rate of 2.8 per cent.

As a check on the projected trend, an estimate of the Province's future population was made according to the trend of Alberta's historic proportion of the total population of Canada. The result so obtained was similar to that of the above detailed study.

Domestic Requirements. Average annual rates of consumption per customer were determined, and saturation levels of customer average annual usage estimated. The number of customers was estimated from the population projections and estimated future rate of household formation. Future annual domestic requirements were determined from the estimated number of customers and estimated average annual customer demand. Allowance was made for communities reaching saturation levels of average annual customer demand at various points in the forecast.

Commercial Requirements. A detailed Province-wide study was made to determine the ratio of domestic customers to commercial customers. A pattern was found to exist in that ratio which was related to the size of the community. In large centres the ratio is about 10:1, while in the small isolated communities there are some three domestic customers to every commercial customer. As the population of a community grows, the commercial establishments tend to increase in number at a lower rate, but they tend toward larger units.

Industrial Requirements. A forecast for the growth in demand was made for each large industrial consumer and for each group of small industrial consumers served by each utility system. Most of the large consumers were consulted and forecasts of their future requirements were received from them.

In estimating industrial demand, consideration was given to the expected industrial growth of Canada, the growth characteristics of the product being manufactured, the growth record of the individual manufacturer, the markets available and changes in processes which may affect the consumption of gas.

In addition to increases in demand by existing industries, a contingency allowance was made for new, large industrial customers, equal to approximately 400 billion cubic feet for the thirty-year period, or about 8 per cent of the forecast of total thirty-year normal industrial requirement. The presence of lumber, petroleum and metallic mineral resources, combined with the availability of relatively cheap energy, should be conducive to the maintenance of a steady industrial growth in the Province. As in OGCB Report 64-1, February, 1964, 780 billion cubic feet of gas was considered as a requirement during the thirty-year period for the possible processing of iron ore in the Peace River area. An amount of some 800 billion cubic feet was added as being required to cover shrinkage at the Empress plant, and Alberta Gas Trunk Line fuel requirements for the thirty years. This estimate was based on existing permits and the two presently applied for.

A summary of the Board staff forecast is shown in the Table C-2.

Board Forecast

The Board Forecast of February, 1964. The Board's forecast of February, 1964, as presented in OGCB Report 64-1, was based on a review of its 1959 forecast. However, a detailed review of Alberta requirements was made prior to OGCB Report 64-1 because actual requirements during the period, 1959 - 1963, fell short of those forecast. As no new evidence was presented at the hearing of the 1963 Trans-Canada application, and all parties, including the Utilities Companies, indicated general agreement with the total requirements given in the 1959 forecast, the Board believed that the 1959 forecast revised only to take account of lower demand in the base years was appropriate. The result was that, excluding the 780 billion cubic feet of requirement for an iron ore processing facility, the thirty-year requirements as shown in OGCB Report 64-1 were somewhat less than those estimated in the 1959 report.

Population. The Board has reviewed the evidence of the Utilities Companies relating to population growth and the study made by the Board staff. Although the Board realizes that the Utilities Companies did not project population growth for the whole of the Province, it finds substantial agreement in projected rates of growth for those areas studied by the Utilities Companies. However, the Board disagrees in principle with the straight line method of extrapolation as used by the Utilities Companies. It considers that the method of analysis employed by the Board staff, an exponential extrapolation related to long term trends, more appropriate as it allows adjustment for the anomalous elements in the trends of past growth.

The Board thus accepts the Board staff projection of population growth, shown on Figure C-1, which results in an average annual rate of 2.8 per cent.

Domestic and Commercial Requirements. The Board notes that there is very close agreement between the forecasts of the total of domestic and commercial requirements made by the Utilities Companies and the Board staff. It is significant also that, with the exception of the growth rates applied to areas other than those served by the two large utility systems, there was very little criticism of the Utilities Companies' forecast.

The growth rates derived from the Utilities Companies' forecast to reach their terminal year requirements are significantly lower than those necessary to achieve their thirty-year requirements, due to their method of calculating thirty-year requirements. Although a growth rate of 2.8 per cent per year for both categories is indicated as necessary to achieve their terminal year demand, equivalent average annual growth rates of 3.3 per cent for domestic and 3.2 per cent for commercial requirements are indicated to achieve their thirty-year requirements.

The Board believes that in the long term the rate of growth of domestic and commercial sales will vary more or less directly with population growth. However, the trend toward smaller households together with present average annual customer demand somewhat less than projected saturation levels should give rise to a growth somewhat higher for the domestic category than that of the population. On the other hand, one would expect the rate of growth in commercial demand to fall somewhat below that of domestic as towns grow and commercial units expand and consolidate.

On the basis of the evidence, and the review above, and having in mind the growth rate of the population forecast accepted by it, the Board believes that the rate of growth indicated both by the Board staff forecast and the rate necessary to reach the Utilities Companies' forecast of thirty-year domestic requirements to be somewhat high relative to the rate of population growth. Conversely, the Board is of the opinion that the growth rate of 2.8 per cent necessary to reach the terminal year of the Utilities Companies' forecast, equal approximately to that of population, to be too low. It is the Board's opinion that the growth rate of demand for domestic consumption should be somewhere between the 2.8 per cent equivalent growth rate necessary to achieve the terminal year of the Utilities Companies' forecast and the 3.5 per cent rates of the Board staff forecast. The Board has decided that an average annual rate of growth of 3 per cent would be appropriate.

Similarly, the Board is of the opinion that the 2.3 per cent rate for growth of commercial demand indicated by the Board staff forecast to be too low relative to population growth and the 3.2 per cent necessary to achieve the Utilities Companies' estimate of thirty-year requirements too high. It is the Board's opinion that a rate of 2.8 per cent, equal to that of the Board's forecast of population growth to be appropriate. This is similar to the rate necessary to reach the Utilities Companies' forecast of requirements in the terminal year.

Graphical comparisons of the Utilities Companies', Board staff and Board projections of domestic and commercial requirements are shown on Figures C-2 and C-3 respectively.

Industrial Requirements. Little criticism was aimed at the forecast of requirements for basic industrial and special industrial made by the Utilities Companies, but considerable disagreement with their contingency provisions emerged. Much of the support of or disagreement with the contingency depended on views regarding the basis on which future industrial growth in the Province depends. The general view of the applicants and the producer interveners was that the future trend of industrial growth would tend to follow that of population. In fact, it was the explicit opinion of many that new manufacturing industry, which apparently is not necessarily sensitive to fuel costs in locational decisions, would depend directly on the Province gaining significant new population. On the other hand, the Utilities Companies and the city interveners believed that industrial growth is lagging relative to expectations on the basis of natural advantages in Alberta, and in particular, the availability of dependable supplies of low cost fuel.

The Board is of the opinion that it must give significant weight to the evidence of Sherritt Gordon regarding the future of industrial growth in the Province. The Board does not believe that the availability of low cost fuel is an insignificant factor in industrial location, as suggested by witnesses for CPA. The relative significance in the location decision of fuel depends entirely on the type of industry. Although the Sherritt Gordon evidence refers principally to fuel oriented industry, and industry in which gas serves as a raw material, it is the Board's opinion that, as in the past, such industries will form the basis of industrial growth in the future. The Board notes Mr. Snyder's observation that at least one new requirement from such an industry, not provided for in the Utilities Companies' forecast, has already become apparent in a new fertilizer plant located in Calgary with requirements soon to be in excess of 2 billion cubic feet per year. The advantages for industrial location in the Province obviously favour the petrochemical group of industries rather than general manufacturing. The latter would tend to follow as tertiary development. Thus, the Board cannot accept as valid the propositions of the applicants and producer interveners that the level of industrial growth in the future will depend directly on the level of the future population.

Conversely, the Board cannot accept the argument of the Utilities Companies that a measure of growth to be expected in the future is the comparison between the average level of industrial saturation for the country and Province as a whole and that presently maintained in the individual areas of the Province served by the two major utility systems. The nature of the average is such that some areas enjoy high levels of saturation and others low. The Utilities Companies themselves, illustrated this point, showing that the level of industrial consumption in 1964 was some 84 per cent of the total consumption for areas of the Province other than the Utilities Companies' service areas.

The Board notes that the Board staff forecast results in a rate of growth very similar to that necessary to achieve the terminal year requirements of the Utilities Companies' forecast. However, there is considerable difference in comparing the growth rates necessary to achieve the thirty-year requirements of the two forecasts, as shown in Tables C-1 and C-2. The Utilities Companies' forecast of thirty-year requirements, because of their assumption of a linear extrapolation, results in an equivalent annual average rate of growth of 4.8 per cent. The Board staff forecast, resulting in a growth rate of 3.8 per cent assumes a more modest contingency provision than that of the Utilities Companies, but one which still appears reasonable.

It is the Board's opinion that the rate of growth for industrial consumption should lie between that of the Board staff's forecast and the 4.8 per cent required to meet the thirty-year requirements expected by the Utilities Companies. It is the Board's judgment that 4.8 per cent is a rather excessive growth rate and that an annual average compound rate of growth of 4 per cent, slightly higher than that projected by the Board staff, and equivalent to the rate necessary to achieve the terminal year of the Utilities Companies' forecast would be appropriate. The Board's forecast is compared graphically with those of the Utilities Companies and the Board staff on Figures C-4 and C-5.

Total Requirements. In view of its decision to use the formula method outlined in OGCB Report 64-1, and its belief in the greater validity of an exponential extrapolation for a demand projection, as appears to be the pattern of past long-term trends, the Board has decided to use the formula method for the purpose of this report, using the rates of growth indicated in the preceding paragraph. The Board's forecast is shown in Table C-3. The Board has given consideration to Mr. Blair's views regarding the 1957 Stanford forecast, but does not believe that the Stanford projection has much value for a long term forecast. Also, circumstances basic to the forecast have changed since the Stanford study was done, and the Unities Companies, for whom it was made, appear to have rejected it.

A graphical comparison of total requirements for the Utilities Companies, Board staff and Board forecasts is shown on Figure C-6.

Permit Commitments

The present permit commitments, the volumes of gas removed to June 30, 1964, and the maximum daily authorized withdrawal rates, under authority of each of the 29 permits issued, are shown in Table C-4.

At June 30, 1964, permit volumes totalled some 17.0 trillion cubic feet of gas. At this date approximately 2 trillion cubic feet or 17 per cent had been removed.

TABLE C-1

ALBERTA GAS REQUIREMENTS

UTILITIES COMPANIES' FORECAST

(Billions of cubic feet of 1000 Btu gas)

	DOMESTIC	COMMERCIAL	NORMAL INDUSTRIAL (1)	SUB TOTAL	OTHER INDUSTRIAL (1)	TOTAL
1964 Annual	46.0	34.1	86.3	166.4	15.0	181.4
1993 Annual	103.3	75.8	276.5	455.6	61.8	517.4
30-Year Total (2)	2308.0	1688.0	5535.0	9531.0	1440.0	10971.0
Equivalent average annual growth rate to achieve terminal year	2.8%	2.8%	4.0%	3.5%		3.6%
Equivalent average annual growth rate to achieve 30-year total	3.3%	3.2%	4.8%	4.1%		4.4%

(1) Normal Industrial excludes provision for shrinkage at the Edmonton Liquid Gas and Empress extraction plants, Alberta Gas Trunk Line fuel requirements and iron ore processing in the Peace River area. Requirements for these items are included in the "Other Industrial" column. If the requested increases in permit volumes of gas are approved, "Other Industrial" requirements will be increased by 200 billion cubic feet for the 30-year period.

(2) Approximately equal to the average of the first and terminal years multiplied by 30, for the Domestic, Commercial and Normal Industrial categories.

TABLE C-2

ALBERTA GAS REQUIREMENTS

BOARD STAFF FORECAST

(BILLIONS OF CUBIC FEET OF 1000 BTU GAS)

	DOMESTIC	COMMERCIAL	NORMAL INDUSTRIAL (1)	SUB TOTAL	OTHER INDUSTRIAL (1)	TOTAL
1964 ANNUAL	47.9	32.3	90.3	170.5	15.3	185.8
1993 ANNUAL	124.2	64.0	269.7	457.9	62.1	520.0
30-YEAR TOTAL	2475.0	1376.0	4915.0	8766.0	1449.0	10215.0
EQUIVALENT AVERAGE ANNUAL GROWTH RATE TO ACHIEVE TERMINAL YEAR	3.5%	2.3%	3.8%	3.5%		3.6%
EQUIVALENT AVERAGE ANNUAL GROWTH RATE TO ACHIEVE 30-YEAR TOTAL	3.5%	2.3%	3.8%	3.5%		3.6%

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(1) NORMAL INDUSTRIAL EXCLUDES PROVISION FOR SHRINKAGE AT THE EDMONTON LIQUID GAS AND EMPRESS EXTRACTION PLANTS, ALBERTA GAS TRUNK LINE FUEL REQUIREMENTS AND IRON ORE PROCESSING IN THE PEACE RIVER AREA. REQUIREMENTS FOR THESE ITEMS ARE INCLUDED IN THE "OTHER INDUSTRIAL" COLUMN. IF THE REQUESTED INCREASES IN PERMIT VOLUMES OF GAS ARE APPROVED, "OTHER INDUSTRIAL" REQUIREMENTS WILL BE INCREASED BY 200 BILLION CUBIC FEET FOR THE 30-YEAR PERIOD.

TABLE C-3

ALBERTA GAS REQUIREMENTS

BOARD FORECAST

(Billions of cubic feet of 1000 Btu gas)

	DOMESTIC	COMMERCIAL	NORMAL INDUSTRIAL (1)	SUB TOTAL	OTHER INDUSTRIAL (1)	TOTAL
1964 Annual	47.9	32.3	90.3	170.5	15.3	185.8
1993 Annual	112.8	72.1	286.6	471.5	62.1	533.6
30-Year Total	2278.9	1487.3	5124.5	8890.7	1449.0	10339.7
Equivalent average annual growth rate to achieve terminal year	3.0%	2.8%	4.0%	3.5%		3.7%
Equivalent average annual growth rate to achieve 30-year total	3.0%	2.8%	4.0%	3.5%		3.7%

(1) Normal Industrial excludes provision for shrinkage at the Edmonton Liquid Gas and Empress extraction plants, Alberta Gas Trunk Line fuel requirements and iron ore processing in the Peace River area. Requirements for these items are included in the "Other Industrial" column. If the requested increases in permit volumes of gas are approved, "Other Industrial" requirements will be increased by 200 billion cubic feet for the 30-year period.

TABLE C-4

PERMIT COMMITMENTS

(All volumes at 14.65 psia and 60°F)

PERMIT NUMBER	PERMITTEE	FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	PERMITTED WITHDRAWALS TOTAL BCF	WITHDRAWN TO JUNE 30, 1964 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
AS 59-1 and AS 60-2	Alberta and Southern Gas Co. Ltd.	Beaver Creek, Berland River, Brazeau River, Burnt Timber, Caroline, Carson Creek, Carson Creek North, Crossfield (Rundle Pool), Fox Creek, Fox Creek North, Fox Creek West, Homeglen-Rimbey, Kaybob, Lovett River, Minnehik-Buck Lake, Paddle River, Parkland, Pembina (Lobstick Glauconitic and Lobstick Ostracod Pools), Pine Creek, Stolberg, Waterton, Westerose South, Wildcat Hills, and Windfall.	496.4	165.1	4128.2	358.5	3769.7
BH 61-1 BS 61-1 CS 61-1 COG 61-1 SEL 61-1 JMW 61-1	Delta Gas & Transmission Ltd. Bailey Selburn Oil and Gas Ltd. The California Standard Company Charter Oil and Gas Ltd. Selbay Exploration Ltd. J. Merril Wright, Jr.	Medicine Hat	9.5	3.5	71.0	-	71.0
CD 63-1	Canadian Delhi Oil Ltd.	Medicine Hat	4.3	1.57	32.3	0.6	31.7
CM 54-1 and CM 61-2	Canadian-Montana Pipe Line Company	Aden, Black Butte, Comrey, Manyberries, Pakowki Lake, Pendant d'Oreille, and Smith Coulee.	100.0	20.0	385(1)	162.7	222.3
CP 63-1	Canadian Pacific Oil and Gas Limited	Medicine Hat	0.1	0.0365	0.750	-	0.750

(1) Total initial marketable gas in the fields shown.

1964 ANNUAL

1993 ANNUAL

30-YEAR TOTAL

EQUIVALENT AVERAGE ANN
ACHIEVE TERMINAL YEAR

EQUIVALENT AVERAGE ANN
ACHIEVE 30-YEAR TOTAL

PERMIT NUMBER	PERMITTEE	FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS			WITHDRAWN TO JUNE 30, 1964 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
			MAXIMUM DAY MMCF	MAXIMUM ANNUAL BCF	TOTAL BCF		
CMM 61-1 MOG 61-1 ROC 61-1	J. Ray McDermott & Co. Inc. Mayfair Oil & Gas (1961) Ltd. Richfield Oil Corporation	Medicine Hat	8.3	3.0	62.0	1.1	60.9
HB 63-1	Hudson's Bay Oil and Gas Company Limited	Medicine Hat	1.02	0.372	7.65	0.1	7.55
SPC 57-1	Many Islands Pipe Lines Ltd.	Medicine Hat	135.5	44.5	609.4	59.3	550.1
NSU 64-1	The British American Oil Company Limited, Royalite Oil Company, Limited, Sun Oil Company and United Canso Oil & Gas Ltd.	Antelope and Esther	11.4	4.2	40.0	-	40.0
-	Peace River Transmission Company Limited	Pouce Coupe	6.0	0.60	13.0	11.3	21.4
-	Peace River Transmission Company Limited	Pouce Coupe South	6.9	0.98	19.7		
-	Patrick T. Buckley	Vanalta No. 4 Well	1.3 MMcf Per Mo.	0.010	-		
PG 64-1	Provo Gas Producers Limited	Wildunn Creek	5.0	1.8	25.0	0.6	24.4
TC 64-5	Trans-Canada Pipe Lines Limited	Atlee-Buffalo, Bindloss, Carstairs, Cessford, Chigwell, Connorsville, Countess, Crossfield (Cardium Pool), Crossfield East, Enchant, Erskine, Fenn-Big Valley, Fenn West, Gilby, Hackett, Hamilton Lake, Harmattan-Elkton (Rundle A Pool), Homeglen-Rimbey, Hussar, Innisfail, Kessler, Lone Pine Creek, Medicine Hat, Minnehik-Buck Lake, Nevis, Olds, Oyen, Pincher Creek, Prevo, Princess, Provost,	1240.0	425.0	9640.0	1150.1	8489.9

1964 ANNUAL

1993 ANNUAL

30-YEAR TOTAL

EQUIVALENT AVERAGE ANN
ACHIEVE TERMINAL YEAR

EQUIVALENT AVERAGE ANN
ACHIEVE 30-YEAR TOTAL

PERMIT NUMBER	PERMITTEE	FIELDS UNDER PERMIT	PERMITTED WITHDRAWALS MAXIMUM DAY MMCF	PERMITTED WITHDRAWALS MAXIMUM ANNUAL BCF	PERMITTED WITHDRAWALS TOTAL BCF	WITHDRAWN TO JUNE 30, 1964 BCF	REMAINING AUTHORIZED WITHDRAWAL BCF
TC 64-5 (cont)	Trans-Canada Pipe Lines Limited	Retlaw, Rich, Sedalia, Sibbald, Standard, Stettler, Sylvan Lake, Three Hills Creek, Verger, Wayne-Rosedale, Westerose South, Wimborne and Wood River.					
WC 52-1	Westcoast Transmission Company Limited	Belloy, Braeburn, Burnt River, Eaglesham, Gordondale, Pouce Coupe, Pouce Coupe South, Saddle Hills, and Tangent.	90.0	52.0	870.0	162.2	707.8
WC 59-3	Westcoast Transmission Company Limited	Crossfield (Crossfield Calgary Basal Quartz, Rundle, and Wabamun Pools), and Savanna Creek.	162.2	53.1	1081.2	102.0	979.2
WC 61-4	Westcoast Transmission Company Limited	Boundary Lake South	Volumes not to exceed those authorized in Permit No. WC 52-1.				
WC 62-5	Westcoast Transmission Company Limited	Worsley	53.8	16.0	220.0	24.7	195.3
		TOTALS	2429.92	791.7685	17205.20	2033.2	15172.0

1964 ANNUAL

1993 ANNUAL

30-YEAR TOTAL

EQUIVALENT AVERAGE ANN
ACHIEVE TERMINAL YEAR

EQUIVALENT AVERAGE ANN
ACHIEVE 30-YEAR TOTAL

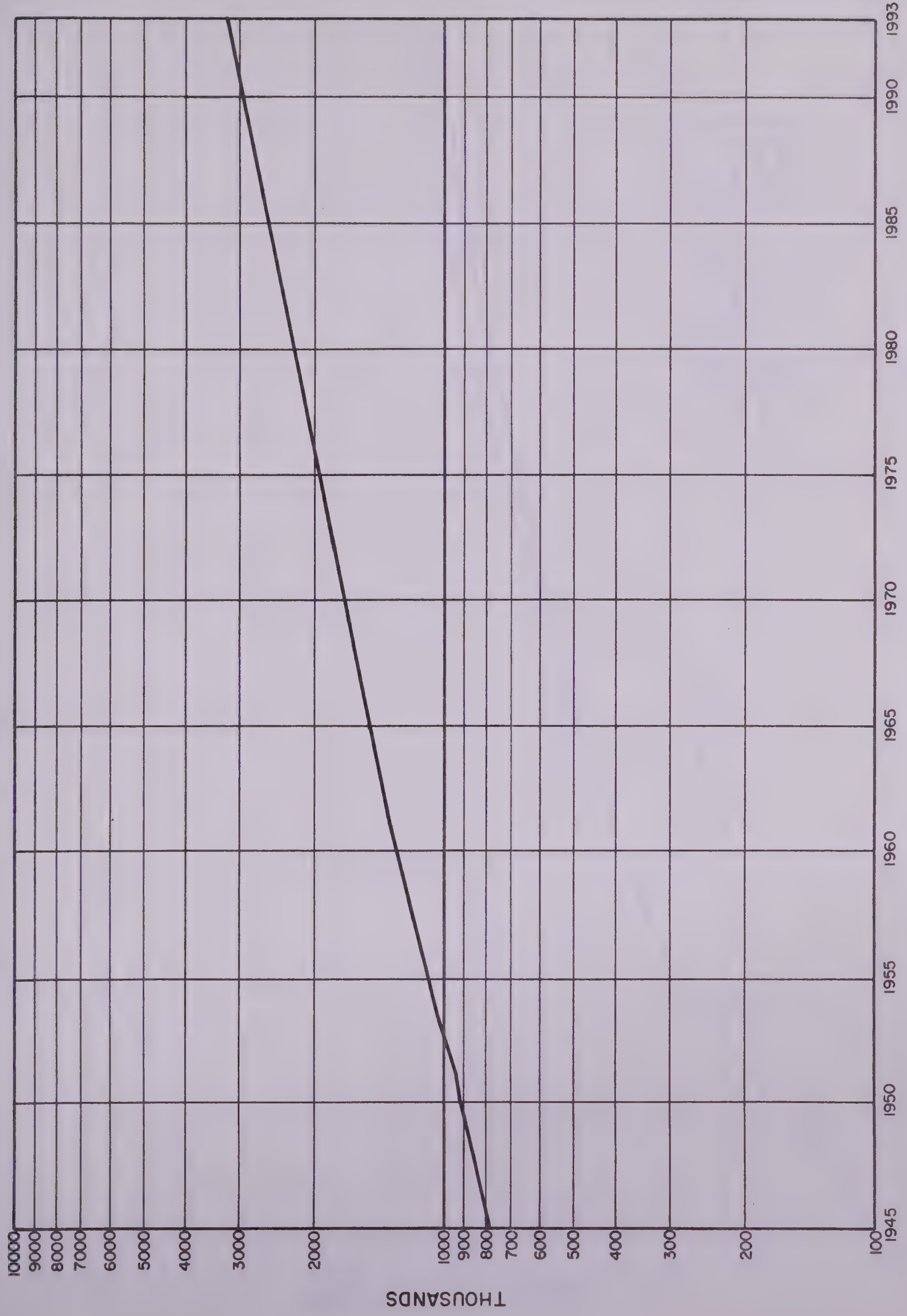

FIGURE C-1 —FORECAST OF ALBERTA POPULATION

OIL AND GAS CONSERVATION BOARD
CALGARY, ALBERTA NOVEMBER, 1964

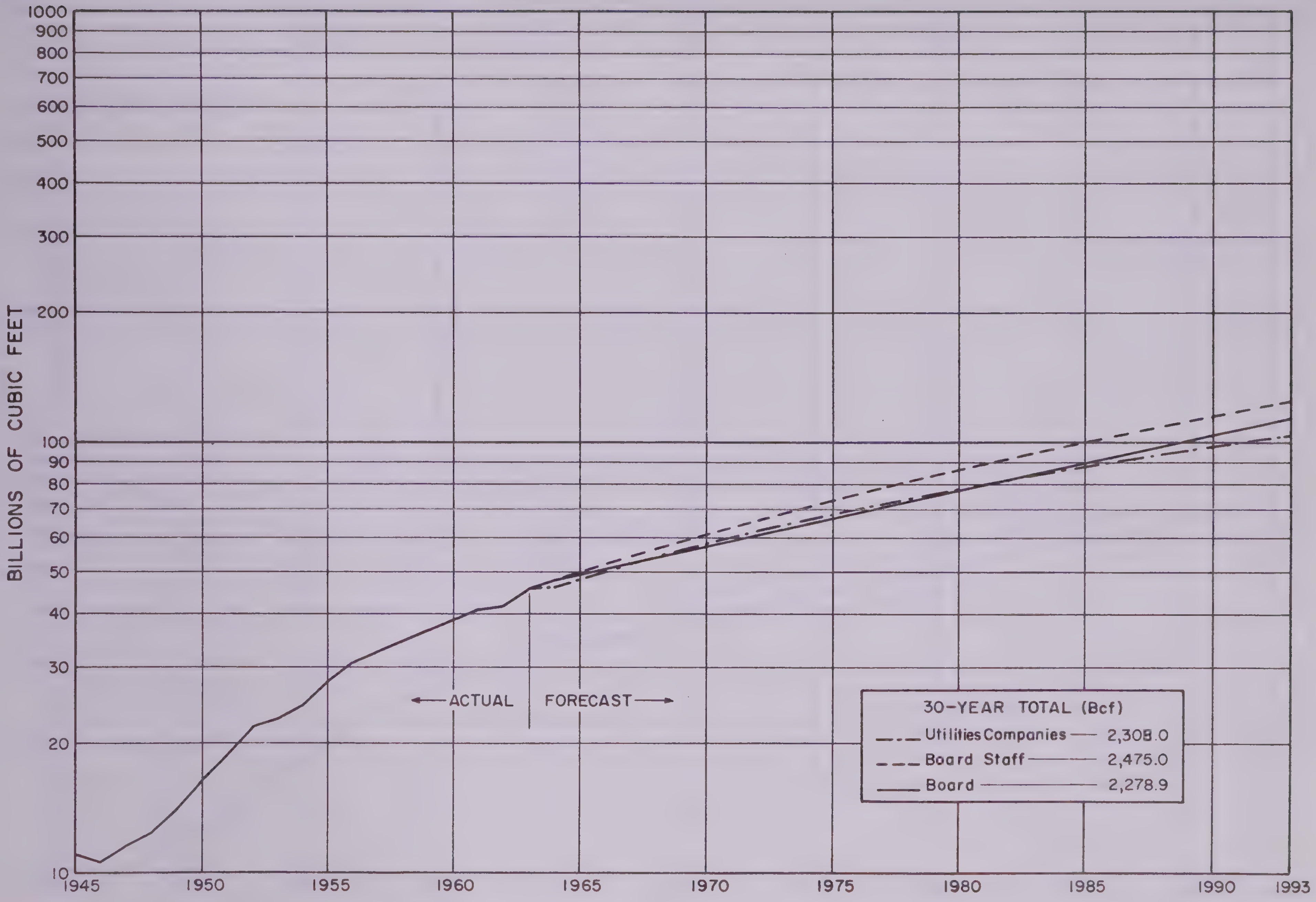

FIGURE C-2—COMPARISION OF FORECASTS OF ALBERTA DOMESTIC GAS REQUIREMENTS

OIL AND GAS CONSERVATION BOA
CALGARY, ALBERTA NOVEMBER, 19

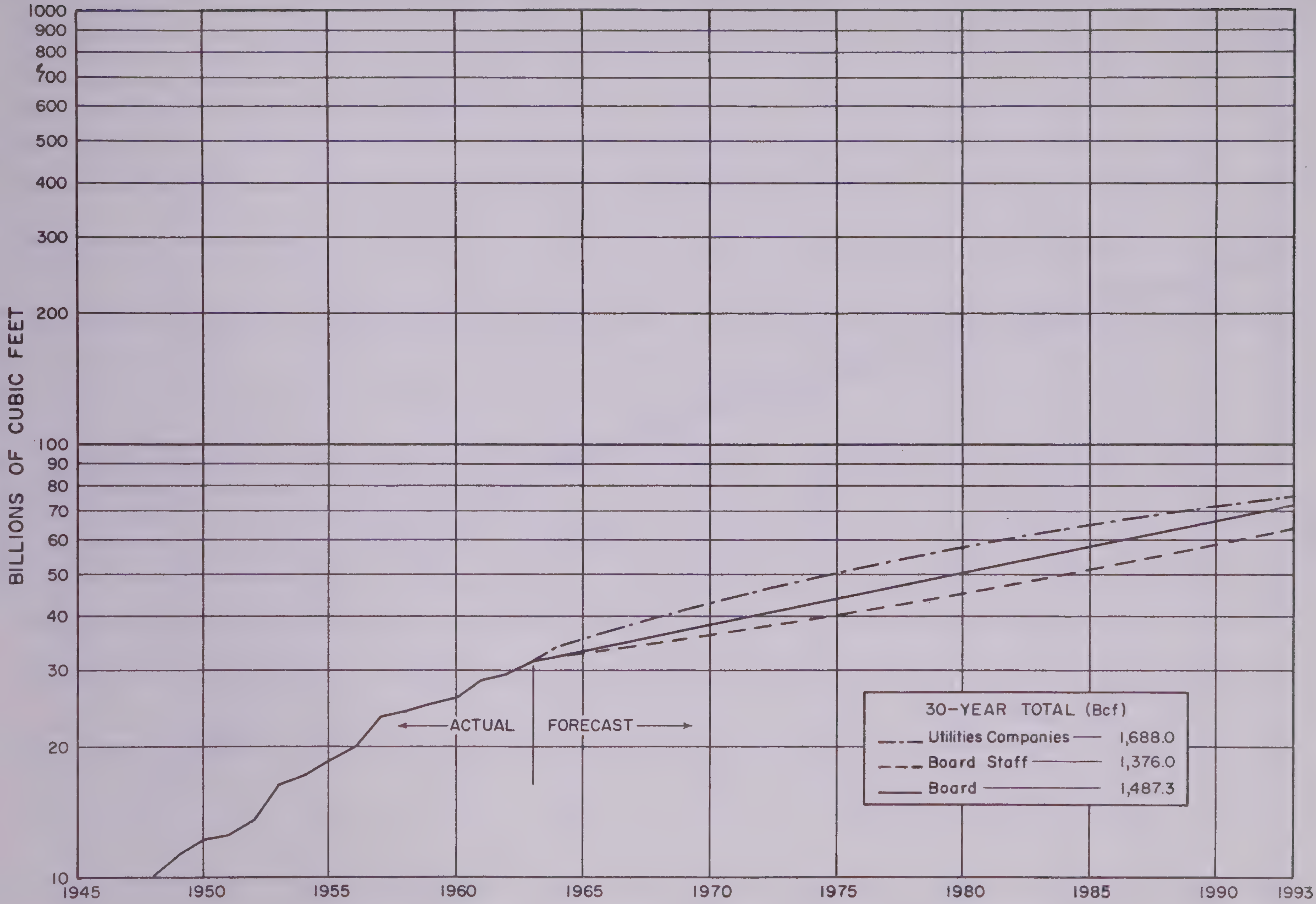

FIGURE C-3 — COMPARISION OF FORECASTS OF ALBERTA COMMERCIAL GAS REQUIREMENTS

OIL AND GAS CONSERVATION BOAR
CALGARY, ALBERTA NOVEMBER, 196

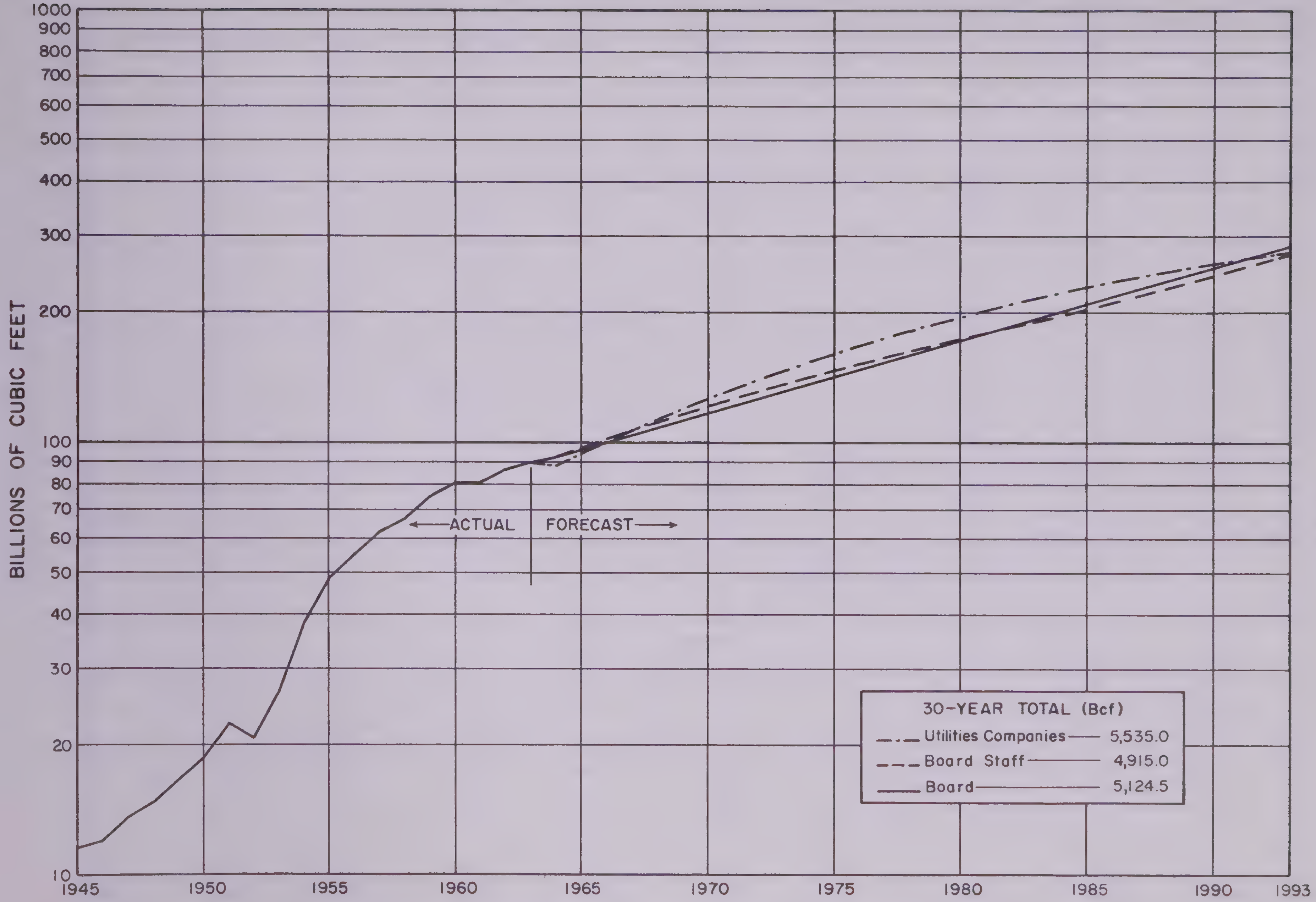

FIGURE C-4 — COMPARISION OF FORECASTS OF ALBERTA NORMAL INDUSTRIAL GAS REQUIREMENTS

OIL AND GAS CONSERVATION BOARD
CALGARY, ALBERTA NOVEMBER, 1964

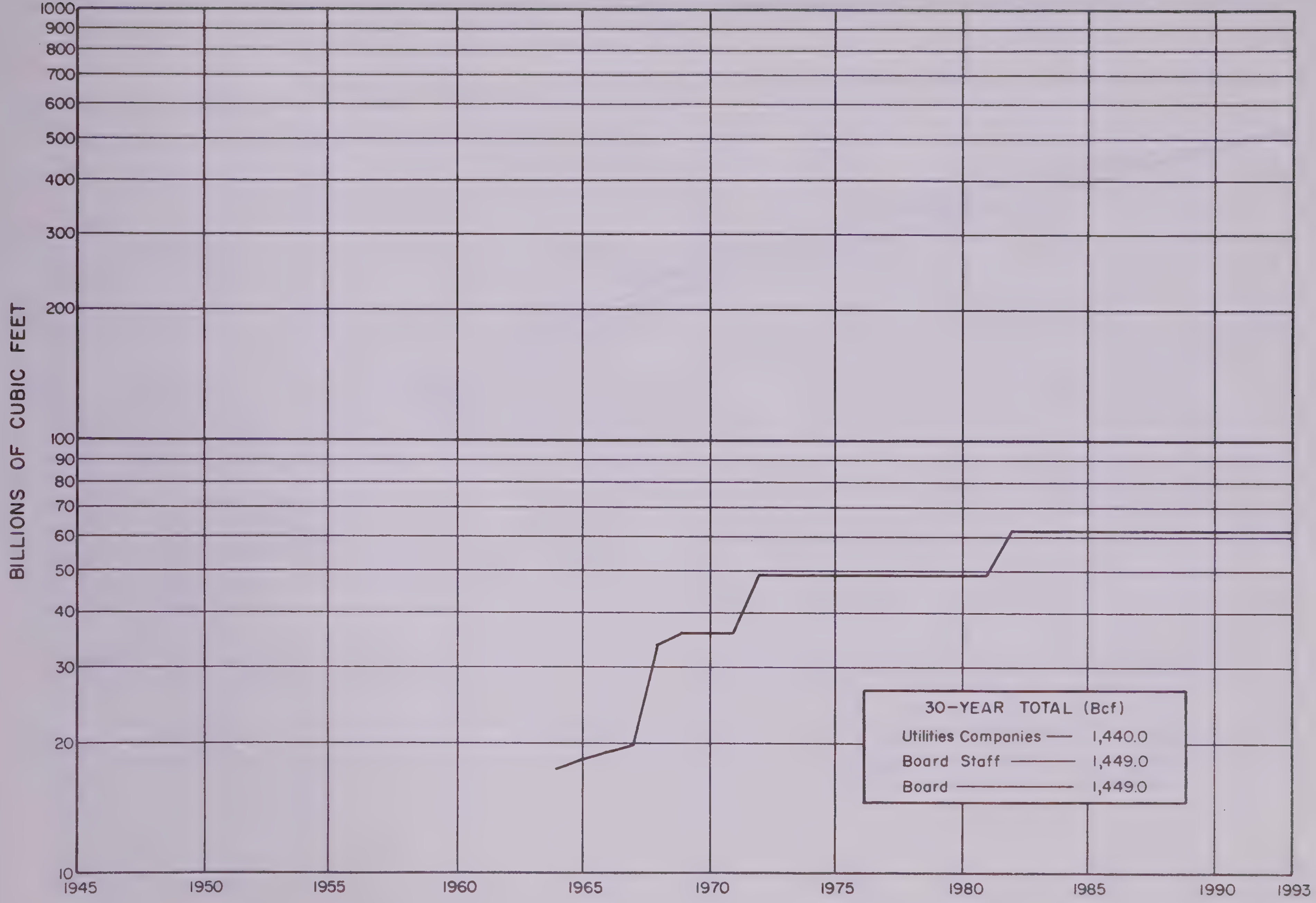

FIGURE C-5 — FORECAST OF ALBERTA
OTHER INDUSTRIAL GAS REQUIREMENTS

OIL AND GAS CONSERVATION BOARD
CALGARY, ALBERTA NOVEMBER, 1964

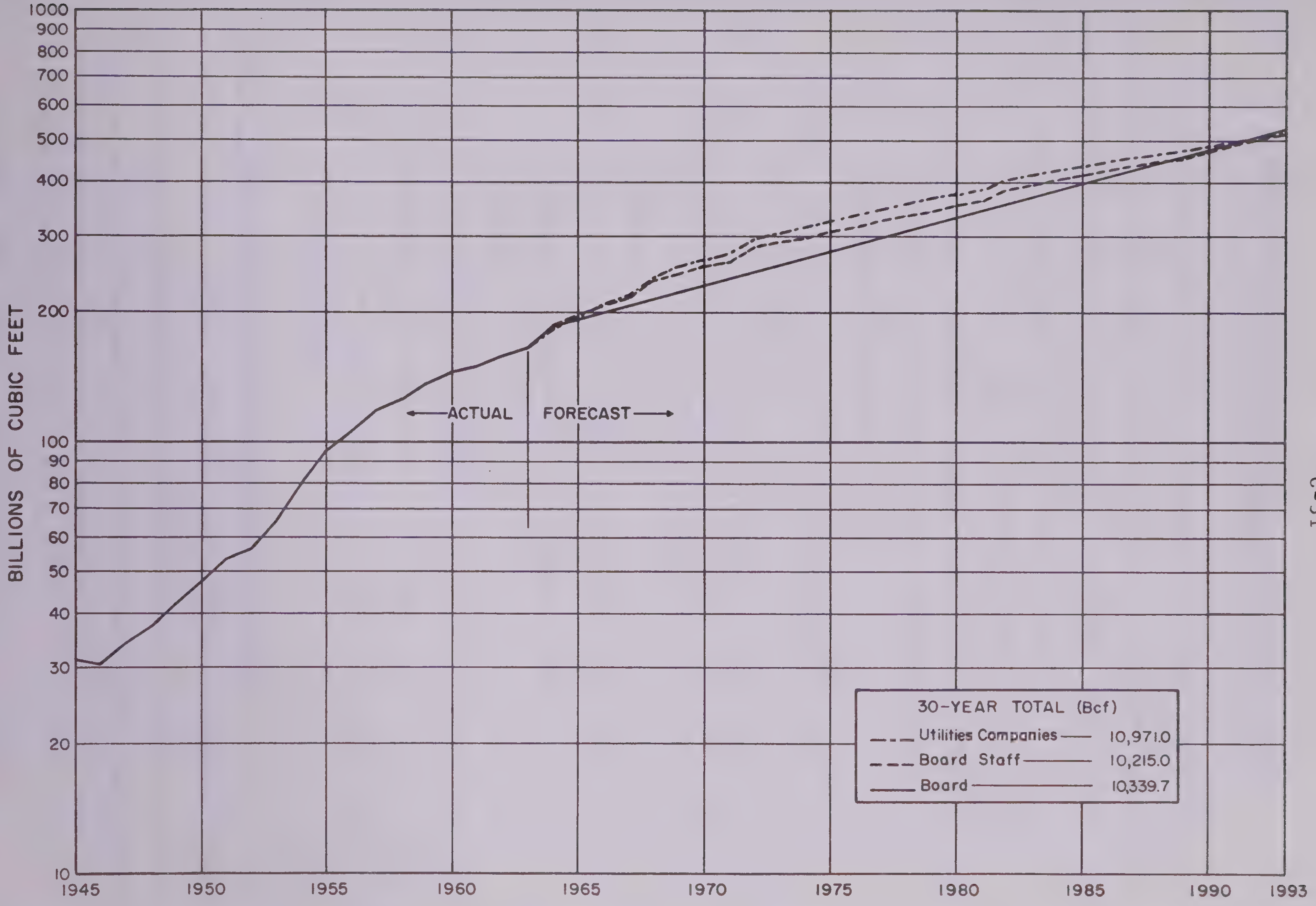

FIGURE C-6 — COMPARISION OF FORECASTS OF ALBERTA TOTAL GAS REQUIREMENTS

OIL AND GAS CONSERVATION BOAR
CALGARY, ALBERTA NOVEMBER, 196

APPENDIX D

OTHER MATTERS ARISING OUT OF THE APPLICATIONS AND INTERVENTIONS

Within the scope of this Appendix are several matters which were discussed at either or both of the subject hearings, but do not logically fit into any of the other Appendices. They appear herein under the following headings:

(a) Use of "Trend" Gas in Computing Alberta's Surplus.

(b) Gas Now Considered to be Beyond Economic Reach.

(c) Recognition of Trends in the Growth of Extra-provincial Requirements.

(d) Protection for Full Deliverability to the Terminal Date of Permits.

(e) Permit Conditions Requested by the City of Calgary.

(f) Allocation of Particular Reserves to the City of Edmonton.

(g) Classification of Gas Reserves and Requirements as Presently Contractable and Contractable for in the Future.

(h) Relationship of Incentive to Drill Wells and the Removal of Gas from the Province.

(i) Protection of the Alberta Consumer from Excessively High Gas Prices.

Use of "Trend" Gas in Computing Alberta's Surplus

In calculating the estimated gas surplus to Alberta requirements, Trans-Canada adopted the method used by the Board in its Reserve Report of December 31, 1963,(1) wherein reserves amounting to two years of expected growth, based on the trends in growth of Alberta reserves, are deemed to be available for meeting a portion of the thirty-year Alberta requirements.

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(1) OGCB Report 64-8. Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur - Province of Alberta, December 31, 1963.

Alberta and Southern, in its assessment of the present surplus, used all of the future appreciation of established reserves plus those reserves expected to be discovered during the next five years in satisfying Alberta's thirty-year requirements. This is roughly the equivalent of three years' growth at the long term growth rate rather than the two years that the Board now uses.

British American Oil, Hudson's Bay, Great Plains, Pan American, Shell, Tenneco, CPA and IPAC supported the current Board practice of using trend gas as part of the supply which would be available to meet future requirements. However, the majority of these interveners suggested that using only two years of gas reserve growth is conservative and reflects only a modest recognition of the gas finding potential of the Province. The consensus appeared to be that at least five years of trend gas should be used in estimating the future supply of gas.

The Utilities Companies opposed the use of trend gas for satisfying provincial requirements mainly because in recent years the growth in gas reserves has been less than the total growth in markets (both within and out of the Province) being served from the reserves. Under cross-examination, Mr. Willson, appearing for the Utilities Companies, testified that he did not doubt that the Board's estimate of two years of trend gas might be developed over the next thirty years, but that such gas would not necessarily become available for the needs of Alberta. This, he explained, was due to the growth in extraprovincial markets and the resulting applications by permittees for the removal from the Province of these new reserves. He also stated that if two years' trend gas is used to help satisfy provincial requirements, then the thirty-year requirements should be estimated as they would be commencing two years from now.

Mr. Davies, a witness for the City of Calgary, stated that the City agreed with the Utilities Companies opposition to the use of trend gas in meeting Alberta's requirements. However, he later stated that the City of Calgary did not oppose the immediate removal of additional quantities of gas from the Province provided that certain conditions (to be discussed later in this Appendix) were included in the permits.

The City of Edmonton also supported the submission of the Utilities Companies. Mayor Hawrelak of the City of Edmonton, when questioned, stated specifically that in his opinion the entire thirty-year provincial requirements should be protected for with proved or established reserves of gas.

The authority by which the Board regulates the removal of gas from the Province is The Gas Resources Preservation Act, 1956. Section 8, subsection (3) of this Act states:

(3) The Board shall not grant a permit for the removal of gas or propane from the Province unless in its opinion it is

in the public interest to do so having regard to

(a) the present and future needs of persons within the Province, and

(b) the established reserves and the trends in growth and discovery of reserves of gas or propane in the Province.

The Board interprets clause (b) of section 8, subsection (3) to be a definite directive to have regard to the trends in the growth and discovery of reserves and cannot agree with the Utilities Companies contention that this regard should be tempered with a consideration of the growth in extraprovincial markets. (The Board's views with respect to growth in extra-provincial markets are presented later.) Bearing in mind the fifteen years or so of available data regarding the growth of gas reserves and its remarkable long term consistency, the Board is convinced that some weight should be given to the expected growth in reserves when consideration is being given to the future needs of persons within the Province.

The available data have been reviewed and analysed in Appendix B and lead to the conclusion that on the average, reserve growth of gas in the Province of about 2.5 trillion cubic feet per year may be expected with confidence. The Board believes that average reserve growth at this rate for the next few years may be counted upon with as much reliability as presently established reserves. In fact, the Board has no serious disagreement with the contention of Alberta and Southern and many of the interveners that as much as five years of trend gas could be included with established reserves in assessing the protection for Alberta's future needs. However, the Board believes it should be particularly conservative in this matter and has decided to use only the expected growth over a two-year period when considering the problem of meeting Alberta's thirty-year requirements. This is consistent with the Board's practice of the past five or six years and is thought to be reasonable as well as conservative. In calculating the two year growth figure, the Board's policy is to use the lesser of the actual growth in reserves over the previous two years or two years of growth at the long term growth rate.

Gas Now Considered to be Beyond Economic Reach

Trans-Canada in its calculation of reserves surplus to Alberta requirements used the method adopted by the Board in its Report of February, 1964,(2) wherein supply was calculated as that amount of marketable gas within economic reach plus a proportion, in that case 50 per cent, of that gas now considered to be beyond economic reach but which the Board estimates would become within economic reach during the thirty-year period. Trans-Canada accepted the Board's estimate of gas considered beyond economic reach as of December 31, 1963, of 3.8 trillion cubic feet. In its Submission of Rebuttal, Trans-Canada cited a study to determine what portion of these reserves considered beyond economic reach as of December 31, 1963, have in fact now become within economic reach or are expected to become so within the next thirty years. The applicant found that 46 per cent of these reserves have become within economic reach since December 31, 1963, and that a further 21 per cent would become so in the near future. The applicant, therefore argued that a minimum of two-thirds of the gas reserves beyond economic reach as of December 31, 1963, should be included as being within economic reach when determining the reserves which are excess to Alberta's thirty-year requirements and the permit commitments.

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(2) OGCB Report 64-1. Report on an Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956.

Alberta and Southern also analysed the reserves considered to be beyond economic reach by the Board, as of December 31, 1963, and found that 53 per cent of these reserves have now become within economic reach or will become so within the next thirty years.

The Independent Petroleum Association of Canada submitted that there was sufficient justification to assume that a portion of the gas reserves presently classed by the Board as beyond economic reach will be within economic reach within the next thirty years. It claimed that 45 per cent of the gas considered beyond economic reach in the Board's June 30, 1953, reserve estimates was actually connected to market by September 30, 1963.

The Utilities Companies opposed the use of any portion of the reserves now considered beyond economic reach, contending that such a practice seriously reduces the protection afforded to Alberta consumers. They argued that it was unsound to look at the forecast market at a particular time and assume that market will be served from gas to be discovered or gas to become economic in the future, because this gas is needed for future markets not yet forecast.

Although the Utilities Companies did not make any studies, Mr. Maybin, when examined, stated that most of the reserves in question were now considered beyond economic reach even though pipe lines were fairly close to them and that they were in this category primarily because of their size. He stated that some of these reserves may become economic through enlargement, but that this was covered by the Board's use of trend gas.

Mr. Davies, appearing for the City of Calgary, supported the stand taken by the Utilities Companies with respect to reserves now beyond economic reach.

The Board has carried out a study of the reserves which were considered beyond economic reach, as of December 31, 1960, and has found that of the 1,870 billion cubic feet some 1,570 billion cubic feet remained beyond economic reach, as of June 30, 1964. This means that in the three and one-half year period some 16 per cent of the reserves were either connected to pipe lines or developed to such a degree that they could be classed within economic reach. During this period there were also other reserves discovered, which were placed within the beyond economic reach category for a one to two-year period and then classed within economic reach due to the rapid development of the reserves.

The Board has also completed a detailed study of the reserves now considered beyond economic reach, having in mind the magnitude of each reserve, its location, the nearness of pipe lines, and the expected development in drilling and in transportation facilities. On the basis of its study, the Board is convinced that at least one-half of the reserves now considered beyond economic reach will be supplying a market within thirty years.

With respect to the argument of the Utilities Companies that use of a portion of this gas is duplicated in the use of trend gas, only the growth in the reserves which are shifted from beyond to within economic reach is included in the overall "growth" figure. It is true that a small portion of the two-year growth figure used by the Board will be gas beyond economic reach but adjustment for this is not thought necessary in view of the arbitrariness of the two years in the first instance. Therefore, the Board has decided to continue including the appropriate proportion (currently judged to be one-half) of the reserves now considered beyond economic reach in its calculations of gas surplus to Alberta's requirements and the present permit commitments.

Recognition of Trends in the Growth of Extraprovincial Requirements

The Utilities Companies argued at both of the subject hearings that any consideration by the Board of the trend in the growth of gas reserves should be balanced not only against the future needs of the Province but against the trend in growth of extraprovincial markets. Mr. Willson, on behalf of the Utilities Companies, stated that his interpretation of The Gas Resources Preservation Act, 1956, is that "the public interest" should include a consideration of the growth of extraprovincial markets. In his opinion the permittees would not be in a position to reduce service to customers at some future date if extraprovincial markets continued to grow at a rate greater than the reserve growth rate. This might place the Alberta consumer in a position of having to compete with consumers outside the Province for future gas supplies. Mr. Willson stated that the Utilities Companies believe that planning should be done at this stage to avoid a situation where customers in California or Eastern Canada may have their future gas supply curtailed because of insufficient supply for their markets as well as Alberta's markets.

The City of Calgary supported the view of the Utilities Companies that some recognition should be given trends in the growth of extraprovincial requirements. On the other hand, Trans-Canada and Alberta and Southern through cross-examination, both opposed this view.

The Board has carefully considered its responsibilities under The Gas Resources Preservation Act, 1956, and cannot agree with the Utilities Companies that consideration should be given the trend in the growth of extraprovincial requirements.

The Board believes that each application for the removal of gas from the Province should be considered strictly on its merits in the light of the projected requirements of the Province and the established reserves and trend in the growth of reserves at the time of the application. The Board does not consider that its approval of the removal of a specified volume of gas carries with it any commitment or understanding whatsoever beyond that spelled out in the permit which it issues. Any additional volumes of gas which might be required to meet growth in the market served by volumes under permit would, under The Gas Resources Preservation Act, 1956, have to be the subject of a further application which would be heard and decided on its merits.

Protection for Full Deliverability to the Terminal Date of Permits

The Utilities Companies in their analysis of the surplus of gas in the Province included in the commitment for removal from the Province, protection for full deliverability to the terminal date of the permits even in those cases where the permit itself indicated that full deliverability was not anticipated in the later years of the period of the permit. They argued that the permittees would not be in a position to reduce deliveries to customers at future dates and would require additional quantities of gas, in some cases from fields not in the permits, to provide full deliverability throughout the permit periods. This interpretation appears to be based on the Utilities Companies view that there perhaps is a moral responsibility on the part of the Board to protect for requirements of areas presently being served with gas from the Province.

As previously stated, the Board assumes no such responsibility and does not agree that cushion gas protection should be afforded in all cases for full deliverability to the terminal dates of permits. In fact, the Board believes it is in the public interest to grant permits which include a period of declining deliverability so the permittees will be given the opportunity of completely depleting those fields included in permits. Protection for full deliverability throughout the period of a permit might result in a partial depletion of a greater number of fields and in a number of fields being turned over to local supply following expiration of the permit at a time when the deliverability has declined substantially. This could result in a high cost of gas to the consumer.

Permit Conditions Requested by the City of Calgary

The City of Calgary in its submission stated it was not opposed to removal of additional gas from the Province, provided the following conditions were included in the permits:

(a) That the applicant shall supply to Canadian Western Natural Gas Company Limited (hereinafter referred to as the "Utility"), which distributes gas to the consumers of gas in Calgary, in priority to any gas exported by it, any gas which the consumers of gas in Calgary may require during the lifetime of the permit or any extension thereof;

(b) That the price to be paid for such gas to Alberta and Southern Co. Ltd. by the Utility on behalf of the consumers in Calgary shall be the lowest price being paid by the said applicant for gas under its Gas Purchase Contracts;

(c) A continuation of the present condition of calculating transportation cost from the nearest point of supply.

Under questioning, Mr. Davies, called by the City of Calgary, stated that the City is not satisfied with clauses 10 and 11 of the form of permit included in the Board's report on the last preceding Trans-Canada application, dated February, 1964.(3) The main reason for this dissatisfaction is because the clauses do not specifically state that the permittee must supply a public utility, but rather that the permittee will supply gas at a reasonable price to any community or consumer within the Province that can reasonably be so supplied. Mr. Davies said the City also objects to the portion of the clause "can reasonably be so supplied" and believes it should be replaced by wording such as "in priority to any gas exported by it". In his opinion, the existing clause means Alberta consumers can only obtain gas from a permittee if the Board finds that the permittee can supply the gas without jeopardizing its requirements for its extraprovincial market. The City of Calgary argued that this is not adequate protection for local consumers.

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(3) OGCB Report 64-1. Report on an Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956. February, 1964.

With respect to clause (b) as requested by the City of Calgary, Mr. Davies stated that in his opinion the only fair price for gas delivered to Alberta consumers would be the lowest price being paid by the permittee. He agreed under questioning, that this might have the effect of shifting a portion of the cost of Alberta consumers gas to either the permittee or its extraprovincial customers, but stated that he believed there is justification for such a situation.

An Alberta and Southern witness, Mr. Blair, stated that the first and second of the conditions proposed by the City of Calgary were not acceptable to that applicant. They would create insurmountable difficulties in other jurisdictions and cause financial and business difficulties. Mr. McNeill, speaking for Trans-Canada, stated that "it could not get by with the conditions suggested by the City of Calgary without the safeguarding of an arbitrator who would settle any dispute or clarification required in connection with either supply or price. We would suggest, sir, that this Board and the Public Utilities Board, as presently named, must be retained in those conditions.".

With respect to the question as to whether "community or consumer" includes a public utility serving such communities or consumers, the Board is prepared to alter the clause and insure public utilities a supply of gas provided it "can reasonably be so supplied".

With respect to the suggestion of the City of Calgary that the words "can reasonably be so supplied" be replaced by "in priority to any gas exported by it", the Board believes the present wording to be adequate. It's interpretation of this clause is that priority would be given provided only that the gas in question could physically and economically be supplied to the community or consumer and that there was no other reasonable source for the community or consumer.

With respect to the second of the clauses requested by the City, in the opinion of the Board the Act does not give it authority to set the price to be paid for gas delivered by permittees to communities or consumers. Such authority is given the Public Utilities Board, and the Oil and Gas Conservation Board recognizes the authority in existing permits.

Allocation of Particular Reserves to the City of Edmonton

The City of Edmonton, in its submission, requested that the Board allocate (dedicate) gas in specific fields sufficient in amount to ensure the Edmonton area needs for the next thirty years. When questioned, Mayor Hawrelak stated that in his opinion such a practice would be desirable for all of the future provincial requirements.

The applicants, Shell and CPA all opposed this approach, contending that it would be unfair to expect producers to develop sufficient gas reserves to satisfy thirty-year requirements and to have to close in these reserves for as much as twenty or thirty years prior to marketing.

Canadian Fina contended that gas sales to local producers are at very near distress prices and that the recent lowering of prices for gas to be removed from the Province (approaching local sales levels) is a direct result of large quantities of gas remaining idle in the ground.

The Board believes that, with the development of The Alberta Gas Trunk Line and the extensive pipe line systems of the major and other utility companies in the Province, adequate protection for the present and future needs of persons within the Province may be afforded without the dedication of individual fields to individual markets. Moreover, the Board believes that the suggestion of the City of Edmonton, if adopted, could result in a situation where a disproportionate share of the obligation of protecting Alberta's requirements would have to be borne by the producer who happens to discover reserves which are subsequently allocated to local communities and is unable to market his gas for many years, thus being deprived of a realistic return on his investment. It might also result in unfair advantage to purchasers of gas for local consumption, when negotiating price with the owners of fields which are allocated to satisfy provincial requirements. For these reasons, the Board is not prepared to designate individual fields for the protection of the requirements of individual communities or consumers.

Classification of Gas Reserves and Requirements as Presently Contractable and Contractable for in the Future

Alberta and Southern at the hearing of its application segregated both the supply and requirement quantities into a presently contractable component and a component contractable for at some future date. It contended that the true surplus should reflect the excess of presently contractable supply over presently contractable requirements, or alternatively the excess of the total assured future supply over the total future requirements including those contractable for in the future.

The Board has considered the Alberta and Southern proposal and although it recognizes certain merits in such an approach, believes that adoption of the proposal would create difficulties in categorizing reserves and requirements (particularly with respect to cushion gas required for provincial requirements). In addition, it would create the possibility of a surplus occurring in the contractable category which might be removed from the Province despite the existence of a deficit in the non-contractable category. This would necessitate greater weight being placed on trends. Also, the procedure recommended by Alberta and Southern would require to a degree, designation of individual fields to individual markets.

As the Board sees it, the overall effects would be a serious reduction in the protection afforded to consumers of gas within the Province. For this reason the Board has decided to continue with the approach it has been using in assessing the balance between gas supply and requirements.

Relationship of Incentive to Drill Wells and the Removal of Gas from the Province

The Utilities Companies in their submission contended that if the applications for permits were denied at this time it would create incentive for the exploration and producing industry to increase its efforts to find the gas reserves which it believes exists, in order to convince the Board and others that there definitely is a surplus of gas within economic reach in the Province. According to the Utilities Companies this would have a beneficial effect on the entire provincial economy.

The applicants, Trans-Canada and Alberta and Southern, argued conversely that there is a direct relationship between the incentive to drill wells and the assurance of markets through the granting of permits for the removal of gas from the Province. They pointed specifically to the period, 1958 to 1961, in which there was a significant increase in the field of gas purchasing. Alberta and Southern stated that in recent years the number of wildcat wells drilled remained fairly constant but there has been a substantial decrease in development drilling resulting in a lower gas reserve growth rate than that experienced previous to 1961.

Most of the exploration and producing companies registered at the hearings,CPA and IPAC supported the applicants in their views with respect to the incentive to develop gas reserves.

The consensus was that a marked decrease in drilling for gas reserves would result if further removal of gas were deferred or denied.

The City of Calgary and the City of Edmonton on the other hand, supported the views of the Utilities Companies.

The Board does not agree with the Utilities Companies that refusal of additional markets would result in an increase in exploratory and development drilling. It recognizes that the very little development of successful gas discoveries which took place during the two to three years prior to the Board's February, 1964 report and before the period of contracting for gas supplies which preceded this application, was most likely due to lack of marketing opportunities.

Protection of the Alberta Consumer from Excessively High Gas Prices

The City of Edmonton in its submission, expressed the view that the local utilities should be absolved from direct competition with permittees for gas supply. Such competition would in the City's opinion, force gas prices further upwards and the Province could lose the advantage of low cost fuel and the associated incentive for industry to locate here.

The City of Calgary agreed with the City of Edmonton that gas prices for Alberta consumers should be protected.

The Utilities Companies contended that the present Board practice of determining the Alberta surplus by balancing against Alberta's thirty-year requirements the amount of gas estimated to be equivalent to two years of trend gas plus one-half of the reserves now considered beyond economic reach, substantially lessens the degree of protection afforded the Alberta consumers and could create a shortage of supply in the foreseeable future. This, they submitted, tends to force gas prices upward. They also stated that as the gas reserves presently serving Alberta are depleted, they must be replaced with gas from more distant sources, resulting in a higher transportation cost from field to market, thus increasing consumer prices.

Sherritt Gordon presented evidence to the effect that one of the reasons for locating its Edmonton area plant in Alberta was the availability of low cost fuel. Concern was expressed at the increasing price of natural gas. Sherritt Gordon believed this increase was due directly to the influence of permitees competing for gas supplies.

Trans-Canada, through cross-examination of the Utilities Companies' witnesses, established that gas prices would be increasing regardless of extraprovincial marketing due to rising costs in exploration, development and transmission. It argued that the permittees were as interested in keeping the price of gas at a reasonable rate as were the Utilities Companies.

Alberta and Southern also questioned the Utilities Companies in this regard, and registered essentially the same opinion concerning prices as did Trans-Canada.

Hudson's Bay in its submission at the Alberta and Southern hearing, stated that the current benefits derived by residents of Alberta, from revenue and incentive associated with the sale of gas for extraprovincial markets far outweigh the disadvantage of nominal price increases.

The interveners who expressed concern about rising gas prices did not object to the overall concept of the removal of gas for extraprovincial markets, but focused their concern on the degree of protection resulting from the Board's method of determining the amount of gas surplus to the provincial requirements and on the terms and conditions in existing permits.

The Board recognizes that the average wellhead price of gas in the Province has increased over recent years and that further increases are probable in the future. The increase is undoubtedly due in part to rising costs of exploration and development, but likely some portion of it has resulted from the market competition generated by the permitting of the removal of substantial volumes of gas from the Province. It is difficult to assess what the overall provincial gas supply situation or the wellhead price of gas would now have been, or would be in the future, if such permits had not been granted. It is likely that fewer reserves would have been discovered and certain that less development of these reserves would have taken place. In addition, even now and more so in the future, additional gas conservation projects are being made feasible, communities which otherwise would not have, are receiving gas service, and the costs of gas transmission for local requirements are being reduced by the removal of gas from the Province. Also, the Province has received substantial direct revenue as a result of the removal of gas, and there is no doubt that the removal has benefited the general level of business activity.

All things considered, and granted that part of the increase in gas wellhead prices may be attributed to the removal of gas from the Province, the Board is convinced that such removal, when there is a surplus calculated by the Board's methods and subject to the terms included in the permits and the resulting protection for the needs of the Province, is in the public interest and is proper and reasonable.

APPENDIX E

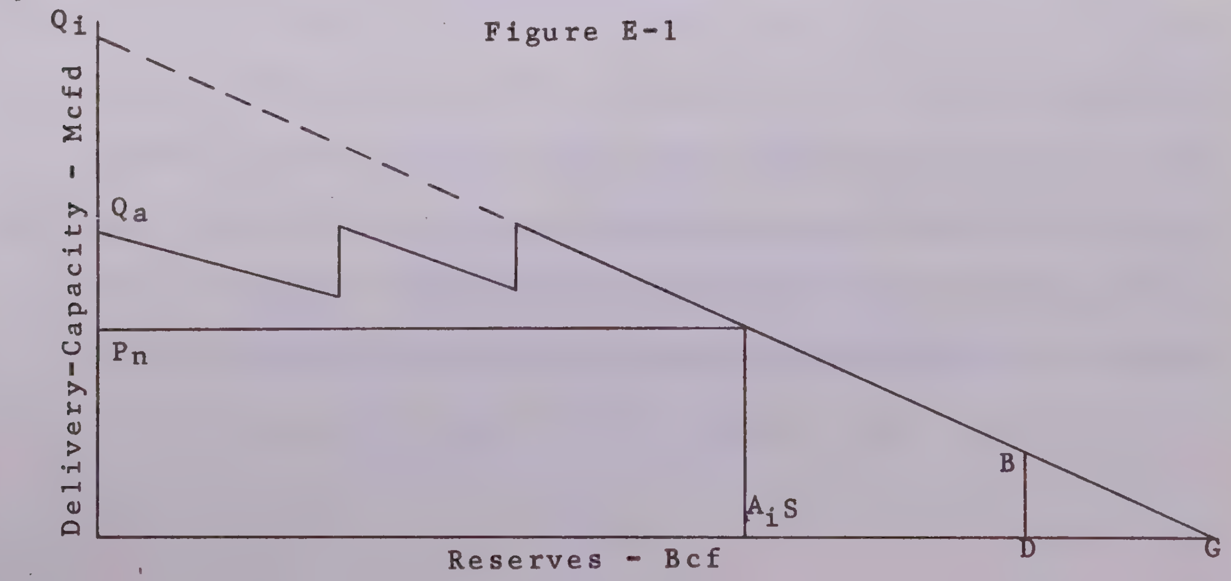
THE MEETING OF ALBERTA'S REQUIREMENTS FOR GAS, THE PRESENT PERMIT COMMITMENTS, AND THE RESULTING SURPLUS

Throughout both hearings considerable discussion centred upon the "formula" approach used by the Board in its more recent analyses of the meeting of the requirements for gas, and upon factors used in the formula. Since it was apparent from the evidence presented at the hearings that some misunderstanding exists throughout industry with respect to this approach, the Board has decided to include in this report a detailed discussion of the formula and its use.

Formula Method for Assessing the Meeting of Requirements for Natural Gas

The Board's present method of estimating future delivery-capacity for a particular gas pool is based on the assumption that the capacity of the pool to produce will decline as a direct function of the remaining reserves of gas in place as the pool is depleted. This means that for any gas reserve, the deliverability throughout its life may be represented graphically as in Figure E-1.

Figure E-1



where

Q_i = total initial pipe line gas delivery-capacity that would exist if a pool were drilled out to the final degree of development before any production is taken;

G = established reserves of pipe line gas in place (the gas in place x the surface loss factor);

D = recoverable reserves of pipe line gas (G x the reservoir recovery factor).

The estimation of the deliverability on an "initial ultimately developed" basis does not necessarily mean that the total deliverability Q_i will ever exist but only that the maximum deliverability over the life of the pool would be represented by the line Q_i-B. In reality, the actual physical deliverability would probably follow more closely the irregular curve Q_a-B, as necessary wells up to the previously discussed maximum are drilled for delivery purposes. (For example, to maintain production at a plant capacity, P_n, as is illustrated in Figure E-1).

This approach to projecting deliverability requires an estimate of the ultimate degree to which a reservoir will be developed as well as an estimate of the producing capabilities of those wells to be drilled in the future. The ultimate number of wells is not necessarily the number of legal spacing units in the field, but is estimated having regard to the number of locations, and, to the number of existing wells and the period for which these wells will meet market requirements or will satisfy plant throughput capacity, the economics of drilling wells to the depth of the reserve, and any knowledge available with respect to the operator's plans for development of the particular field. The delivery-capacity of drilled locations is estimated on the basis of available back pressure or drill stem tests and is normally taken as the lesser of the figure calculated from the Board's maximum daily allowable formula or the ability of the well to produce against normal wellhead operating pressures. For locations to be drilled in the future, the producing capacity is estimated having regard to the test results on neighboring wells and includes a judgment factor based on a comparison of well properties such as pay thickness and permeability. Since deliverability is normally calculated on a residue gas basis, the total wellhead deliverability is adjusted to a pipe line basis by multiplication with the appropriate surface loss factor.

Referring to Figure E-1, if we define

$F = \frac{G}{Q_i}$ = reserve-delivery ratio, billions of cubic feet per million cubic feet per day,

$K = \frac{D}{G}$ = reservoir recovery factor, fraction,

A_1 = annual requirement in the first year of the period considered, billions of cubic feet,

S = summation factor (accounting for growth) for the number of years in the period under consideration,

A_1S = sum of the annual requirements for the period under consideration, billions of cubic feet, and

P_n = terminal year peak day requirement, millions of cubic feet per day,

then the gas in place, G, needed to satisfy cumulative requirements of A_1S with a final year peak day requirement of P_n may be shown to be

$$G = A_1S + FP_n$$

When converting this quantity to marketable gas (as shown by D on Figure E-1), the marketable gas reserves needed R_n, to satisfy the requirements are

$$R_n = K\,(A_1S + FP_n)$$

Use of the above formula to estimate gas needed to satisfy certain requirements gives results essentially the same as those obtained from detailed deliverability schedules when applied to a single pool. For a group or a composite of pools, however, the effective reserve-delivery ratio is greater than that obtained by dividing the total of the reserves by the total deliverability. The amount by which the effective ratio exceeds that calculated from totals varies depending upon the number and size of component pools, the individual reserve-delivery ratios of the pools, the state of depletion of the individual pools and the pattern and load factor of the requirements to be satisfied. In order to adjust the average reserve-delivery ratio for a group of pools to the effective ratio, a composite correction factor, C, has been introduced where

$$F_{effective} = CF$$

then

$$R_n = K\ (A_1S + CFP_n)$$

The composite correction factor for a particular system must be determined by equating the right hand side of the above formula to the total gas necessary to satisfy the requirements being protected for as determined from detailed deliverability schedules. The correction factor in fact, may be defined as the factor which makes the result of the formula approach equal to the result of an analysis utilizing detailed schedules. Experience indicates than an appreciable change is necessary in the make-up, the estimated deliverability, or the demand for a particular system to significantly alter the composite correction factor for that system. For this reason, it has been the Board's practice to determine the correction factors for the various provincial requirement areas and for the extraprovincial systems through detailed deliverability studies and in cases where significant changes have not occurred or where little new data are available, to utilize these factors and the formula approach in analysing gas requirements for several years thereafter.

The above mentioned formula

$$R_n = K\ (A_1S + CFP_n)$$

may also be written as

$$R_n = A_1S + CFP_n - (1-K)\ (A_1S + CFP_n)$$

Since A_1S is the marketable gas reserve needed to meet the actual deliveries, it follows that the remainder of the right hand side of the formula must be the marketable gas needed to meet the terminal year peak day requirement. If we define this quantity of gas as R_p, then

$$R_n = A_1S + R_p$$

where

$$R_p = CFP_n - (1-K)\ (A_1S + CFP_n).$$

As has been mentioned in previous reports, the formula method has been adopted by the Board because

(a) it gives the same overall result as does the detailed illustrative schedule method,

(b) it is much simpler to present,

(c) it does not necessitate the assignment of fields to certain systems for illustrative purposes and as a result does not imply allocation of particular reserves to certain markets, and

(d) it does not require the preparation of detailed schedules each time the requirements for gas are analysed.

The Meeting of Alberta's Long Term Requirements - Evidence of the Applicants and Interveners

Neither Trans-Canada, Alberta and Southern nor any of the interveners at either of the hearings presented detailed evidence to show how Alberta's thirty-year requirements for gas might be met. Trans-Canada did estimate the surplus of gas in the Province employing the method used by the Board in its Report to The Lieutenant Governor in Council dated February, 1964.(1) In its submission, Trans-Canada updated the figures used by the Board in Tables D-4 and E-3 of the February report to represent the surplus as at March 31, 1964, rather than September, 1963. The following table summarizes the changes made by Trans-Canada and the basis on which they were made. (All volumes are in trillions of cubic feet at 1000 Btu per cubic foot).

	Board Estimate (September 30/63)	Difference	Trans-Canada Estimate (March 31/64)
Reserves Within Economic Reach	31.2	+2.6	33.8
From Reserves Beyond Economic Reach	1.9	0	1.9
Less: Deferred Beyond 30 Years	0.5	0	0.5
Trend Gas	3.6	+1.6	5.2
Total Reserves Available	36.2	+4.2	40.4
Reserves Needed to Meet Alberta Requirements	14.4	+0.5	14.9
Reserves Needed to Meet Permit Commitments	16.1	-0.3	15.8
Total Reserves Needed	30.5	+0.2	30.7
Surplus Before Release of Peaking Gas	3.2	+4.0	7.2
Surplus After Release of Peaking Gas	5.7	+4.0	9.7

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(1) OGCB Report 64-1. Report on an application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act,1956.

The Trans-Canada estimate of reserves within economic reach resulted from an adjustment to the Board's year end reserves, reflecting the Trans-Canada estimate of a growth of some 3.0 trillion cubic feet in reserves for nine fields which had undergone significant development during the first three months of 1964. The reserves have also been adjusted to reflect production during this period. The 5.2 trillion cubic feet of two-year trend gas as used by Trans-Canada reflects the long term growth rate of initial marketable gas reserves. The Board in its February report used the actual growth for the preceding two years (some 3.6 trillion cubic feet) which happened to be well below the long term growth rate. The Trans-Canada estimate of reserves needed for Alberta requirements is the Board's estimate extended for an additional year at the same rate of growth, and the reserves needed for permit commitments is the Board's figure adjusted for the 0.3 trillion cubic feet of gas removed under the permits during the period October 1, 1963 to March 31, 1964. The Trans-Canada analysis results in an estimated surplus reserve as of April 1, 1964, of about 7.2 trillion cubic feet before the release of peaking gas and some 9.7 trillion cubic feet after the release of peaking gas, compared to corresponding surpluses estimated in the Board's February report at some 3.2 trillion cubic feet and 5.7 trillion cubic feet as of September 30, 1963.

Alberta and Southern at the hearing of its application, presented an analysis of the supply, requirements and resulting surplus of natural gas in the Province, as of December 31, 1963. To a degree the applicant adopted figures published in the Board's February, 1964, report, but it segregated both the supply and requirement quantities into a presently contractable component and a component contractable for at some future date. For the purpose of comparison, the Board has shown in the following table the surplus as estimated by Alberta and Southern (in total) and the Board's figures as of September 30, 1963. The Alberta and Southern submission actually included those permits applied for at the hearings, in the permit requirements. However, these have been omitted from the table.

	Board Estimate (September 30/63)	Difference	Alberta and Southern Estimate (December 31/63)
Total Reserves from Present Sources	32.6	-0.2	32.4
Trend Gas	3.6	+3.9	7.5
Total Reserves Available	36.2	+3.7	39.9
Reserves Needed to meet Alberta's Requirements	14.4	-0.1	14.3
Reserves Needed to meet Permit Commitments	16.1	-0.7	15.4
Total Reserves Needed	30.5	-0.8	29.7
Surplus Before Release of Peaking Gas	3.2	+7.0	10.2
Surplus After Release of Peaking Gas	5.7	+4.5	10.2

The Alberta and Southern estimate of total reserves from present sources has been taken from the Board's year end reserve report, OGCB Report 64-8. The estimate of trend gas includes the complete appreciation of now established reserves (some 3.0 trillion) plus future discoveries within five years of the time of assessment, including appreciation during this period (some 4.5 trillion). The estimated 4.5 trillion cubic feet of new gas discoveries was based on an analysis of the total of new discoveries which have occurred during the five-year periods following each of the Board's ten reserve reports that are now more than five years old. The reserves needed to meet Alberta's requirements and the existing permit commitments were taken by Alberta and Southern from the Board's February report, and were adjusted slightly to reflect production. The Alberta and Southern analysis results in an estimated surplus of 10.2 trillion cubic feet after protecting for the thirty-year provincial requirements and the existing permit commitments. Alberta and Southern in its analysis, considered that all of the gas required to protect for the peak day of the permits would be produced to meet local requirements during the thirty-year period. This is the equivalent of not requiring any peaking gas for extraprovincial commitments, and as a result the surplus as estimated by Alberta and Southern is the same before and after the release of peaking gas. (If the permits applied for by each of the applicants are considered, the estimated surplus would be some 5.4 trillion cubic feet).

The Utilities Companies in submissions of intervention presented their analysis with respect to the surplus of gas in the Province as of March 31, 1964. The detail of the manner in which the Utilities Companies' estimates differ from those published by the Board in its February report are given in the following table:

	Board Estimate (September 30/63)	Difference	Utilities Companies Estimate (March 31/64)
Reserves within Economic Reach	31.2	+2.8	34.0
From Reserves Beyond Economic Reach	1.9	-1.9	0
Less: Deferred Beyond 30 Years	0.5	0	0.5
Trend Gas	3.6	-3.6	0
Total Reserves Available	36.2	-2.7	33.5
Reserves Needed to Meet Alberta Requirements	14.4	+3.4	17.8
Reserves Needed to Meet Permit Commitments	16.1	-0.3	15.8
Total Reserves Needed	30.5	+3.1	33.6
Surplus Before the Release of Peaking Gas	3.2	-8.0	-4.8
Surplus After the Release of Peaking Gas	5.7	-5.8	-0.1

The Utilities Companies in their assessment of the surplus situation relied on the evidence of Trans-Canada to determine the reserves within economic reach. They did not give recognition to reserves beyond economic reach or to trend gas, contending that the reliance upon that gas now considered beyond economic reach will expose the Alberta consumer to higher fuel costs, and that the use of trend gas is equivalent to reducing the protection period to less than thirty years. The reserves needed to meet Alberta's requirements were based on the Utilities Companies' own estimate of those requirements, the detail of which has been discussed in Appendix C. The result of the Utilities Companies' analysis was a deficit, as of March 31, 1964, of some 0.1 trillion cubic feet after the release of reserves required to protect the peak day in the permits. They argued that very little, if any, significance should be placed on this number since continuing applications for extension of the terms of the permit would likely be made until all of the gas in the permit fields is authorized for removal. They did, in their submission, illustrate the case where protection is afforded the existing permits for full deliverability throughout the entire permit periods. This would require an additional 4.7 trillion cubic feet, increasing the deficit before the release of cushion gas to some 4.8 trillion cubic feet.

The Meeting of Alberta's Long Term Requirements (July 1, 1964 - June 30, 1994) - The Board's Views

As discussed in Appendix C, the thirty-year gas requirements of the Province have been estimated at 10,340 billion cubic feet with a terminal year peak day of 2,500 million cubic feet. The fields now connected to and supplying Alberta's requirements are listed in Table E-1. The table also gives the

Board's present estimate of the remaining reserves of marketable gas and the reserve-delivery ratio of each of the fields. Illustrative deliverability schedules (not reproduced here) prepared by the Board indicate that of the total of some 5,250 billion cubic feet of gas shown in Table E-1 some 4,400 billion cubic feet will be produced during the thirty-year period, and the remaining unproduced reserve will be capable of sustaining a peak day delivery of some 300 million cubic feet in the terminal year. This means that total deliveries of about 5,940 billion cubic feet (10,340 - 4,400 = 5,940) and a terminal year peak delivery of 2,200 million cubic feet per day (2,500 - 300 = 2,200) will be required from other sources. The actual quantities of gas necessary to provide these deliveries may be calculated using the previously discussed formula method. With respect to the factors to be used in the formula, the Utilities Companies at the hearing of the Trans-Canada application contended that since this gas must come in part from established gas reserves not presently connected to local utilities nor authorized for removal from the Province, and in part from gas reserves not yet developed, the formula factors should reflect the delivery characteristics of both of these sources of gas. The Board concurs with the Utilities Companies on this matter and has checked the reserve-deliverability ratio used in its February report. This recent study has confirmed the use of a ratio of 2.4

along with a reservoir recovery factor of 0.85 in protecting for the additional Alberta requirements. The results of the illustrative schedules also confirm the accuracy of the composite correction factor of 1.3 used by the Board in its report of February, 1964. The resulting total marketable gas needed to meet Alberta's thirty-year requirements is:

From now connected sources for actual delivery	4,400		
From additional sources for actual delivery	5,940		
From now connected sources to protect terminal year peak(1)	850		
From additional sources to protect terminal year peak(2)	4,940		
Total	16,130	say	16,100

The requirements protected for in the above analysis include pipe line fuel for the Trunk Line system and the shrinkage anticipated at the Empress Plant for those quantities of gas heretofore approved for removal from the Province. Should the removal of the additional quantities requested by Trans-Canada and Alberta and Southern be approved, this fuel and shrinkage would be increased and the gas needed to meet Alberta's thirty-year requirements would increase by about 0.2 trillion cubic feet to a total of some 16.3 trillion cubic feet.

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(1) i.e. 5,250 - 4,400 = 850

(2) Determined as $R_p = 1.3\ FP_n - (1 - K)\ (1.3FP_n + A_1S)$

$$= 1.3\ (2.4)\ (2{,}200) - (1 - 0.85)\left[1.3\ (2.4)\ (2{,}200) + 5{,}940\right]$$

$= 6{,}864 - 1{,}921 = 4{,}943$; say 4,940 billion cubic feet.

The Remaining Permit Commitments

The permit commitments remaining at June 30, 1964, have been shown in Appendix C to be some 15,170 billion cubic feet with a maximum peak day of about 2,430 million cubic feet prevailing to 1979 and declining thereafter. As in the case of the meeting of Alberta's long term requirements, the Board studied the manner in which these commitments may be met through a detailed year by year illustrative deliverability analysis for each permittee, and from these analyses has determined the appropriate composite correction factor to be used in the formula approach which is presented here.

The fields included in each of the present permits are shown in Table E-2. The table also shows the Board's present estimate of the remaining reserves of marketable gas and the ratio of marketable gas in place to delivery capacity for each field. The table reflects changes in the remaining marketable reserves which have occurred since the preparation of the February, 1964 report, and also re-analyses the reserve-delivery ratios on the basis of new test data and evidence submitted at the hearings. The rather significant change in the average reserve-delivery ratios for each of the Alberta and Southern and Trans-Canada permits results largely from increased deliverability estimates for the Homeglen-Rimbey and Westerose South Fields, while the change for the Westcoast Transmission Company Limited Southern Alberta permit results from new test data for the Crossfield Field.

The results of the Board analysis with respect to the meeting of the present permit commitments are shown in Table E-3. Columns 1 and 2 show respectively the remaining permit commitment and the maximum day authorized in each of the permits. These figures were obtained from Appendix C and have been converted to the basis of 1000 Btu per cubic foot. The expiry date of each of the permits is shown in Column 3. Columns 4 and 5 present the Board's current estimate of the remaining marketable reserves and the reserve-delivery ratio (both obtained from Table E-2), of the fields included in each permit. Column 6 shows the composite correction factor for each of the permittees' systems as determined from the illustrative deliverability schedules. The estimated quantity of marketable gas in place required to meet the peak day commitment in the terminal year of the permit is shown in Column 7. This quantity is obtained using the relationship CFP_n. Column 8 shows the marketable gas equivalent of column 7. The values were obtained by deducting from Column 7 the marketable gas equivalent of the gas that will remain in the reservoir at abandonment, i.e. $(1 - K)\ (A_1S + CFP_n)$. The total amount of marketable gas required to meet the permit requirements, both deliveries and peak day, is shown in Column 9. Columns 10 and 11 present the Board's estimate of the amount of marketable gas in the fields in the permits, excess to the permit commitments before and after the expiry date of each permit.

In the case of the Trans-Canada permit, three entries have been made. The first line gives the quantity of gas which the Board anticipates will be delivered to October 31, 1981, based on projected requirements of Trans-Canada. It can be seen that, at that time, an estimated 2,555 billion cubic feet of gas will remain in the fields in the permit. The second line shows the remainder of the permit commitment, which the Board believes could be produced from this 2,555 billion cubic feet prior to the terminal date of the permit although not necessarily at the approved maximum daily rate. The third line summarizes the entire permit and shows that some 806 billion cubic feet of gas would remain in the permit fields on October 31, 1989, the terminal date of the permit.

It can be seen from Table E-3 that the Board currently estimates a deficiency in meeting the requirements of three of the existing permits. These deficiencies, all in permits held by Westcoast Transmission Company Limited (WC 52-1, WC 59-3 and WC 61-4) were discussed in some detail in the Board's February, 1964, report and remain essentially unchanged since that time.

Table E-3 shows that a total marketable gas reserve of some 18,700 billion cubic feet is required to meet the commitment of all present permits of about 15,600 billion cubic feet with a terminal year peak of some 2,450 million cubic feet per day. Since reserves of almost 20,100 billion cubic feet are available, a surplus of some 1,400 billion cubic feet of gas exists in the fields includes in the present permits. However, after the expiry dates of the permits, several years before the end of the thirty-year period, an additional 3,100 billion cubic feet, the amount needed to meet the terminal year peak day commitment, will become excess to the present commitments.

The reserves available in the Province and the reserves needed to meet the thirty-year requirements of Alberta and the present permit commitments are shown in Table E-4. The table shows that a total of 40.4 trillion cubic feet of gas is available to meet the requirements and commitments. This amount includes a portion of the reserves now considered beyond economic reach and reflects the continued use of trend gas, as is discussed in detail in Appendix D.

Table E-4 shows that the reserves within economic reach (34.1 trillion cubic feet) plus one-half of those beyond economic reach (1.8 trillion cubic feet) less that portion of oil field gas which will likely be deferred beyond the thirty-year period (0.5 trillion cubic feet) results in a total of some 35.4 trillion cubic feet of gas available from present sources. If two years of trend gas (at the long term growth rate of 2.5 trillion cubic feet per year) is added to this, the total reserves available are some 40.4 trillion cubic feet.

The Board has previously estimated that some 16.1 trillion cubic feet of gas will be needed to meet Alberta's long term requirements. This, added to the 18.7 trillion cubic feet required to meet the present permit commitments, gives a total required reserve of some 34.8 trillion cubic feet. Subtracting 34.8 trillion cubic feet from the available reserves of 40.4, results in a surplus of some 5.6 trillion cubic feet. After the expiry dates of the present permits, an additional 3.1 trillion cubic feet of gas will be released from terminal year peak day protection resulting in an overall surplus of some 8.7 trillion cubic feet.

For convenience, certain figures previously presented are duplicated in Table E-5. The Table is an overall comparison of the surpluses estimated by the Board, Trans-Canada, Alberta and Southern and the Utilities Companies. In some instances the figures shown are the Board's interpretation of the submissions presented at the recent hearings. The Board's estimated surplus after the release of reserves needed to protect for peak day requirements of 8.7 trillion cubic feet as of June 30, 1964, represents an increase of some 3.0 trillion cubic feet since September 30, 1963, the date of the last Board estimate. It is, though, some 1.0 and 1.5 trillion cubic feet respectively less than the surpluses estimated by Trans-Canada as of April 1, 1964, and Alberta and Southern as of December 31, 1963. On the other hand, it is almost nine trillion cubic feet more than the figure estimated by the Utilities Companies as of April 1, 1964. The surplus before the release of the reserves needed for peak day requirements is estimated by the Board at some 5.6 trillion cubic feet, an increase of 2.4 trillion in the nine-month period, September

30, 1963, to June 30, 1964. This surplus of 5.6 trillion cubic feet compares to surpluses of 7.2, 10.2 and a deficit of 4.8 trillion cubic feet as estimated by Trans-Canada, Alberta and Southern and the Utilities Companies respectively.

The major reason why the Trans-Canada surplus is larger than the Board's is because the Board has increased its estimate of Alberta requirements (as is discussed in Appendix C) since the February, 1964, report from which Trans-Canada adopted its estimate of requirements.

The surplus estimated by Alberta and Southern, including the reserve growth of the past six months, would be some four trillion cubic feet larger than that estimated by the Board. The major reasons for this are that Alberta and Southern has adopted the previous Board estimate of requirements (as did Trans-Canada) and that it has included trend gas on the basis of five years of new discoveries rather than the anticipated two-year growth as is the Board's policy.

The deficit shown by the Utilities Companies results because they have not included a portion of reserves now beyond economic reach nor have they included any trend gas. In addition to this, they have included protection for their own estimate of Alberta's requirements, which is larger than that estimated by the Board.

TABLE E-1

RESERVES PRESENTLY SUPPLYING ALBERTA'S REQUIREMENTS FOR GAS

(All volumes at 1000 Btu per cubic foot)

Field	Marketable Gas at June 30, 1964 Bcf	Reserve-Delivery Ratio Bcf/MMcfd
Alexander	24	0.5
Beaverhill Lake - Fort Saskatchewan	437	0.8
Bow Island and Foremost	42	0.9
Carbon	128	1.5
Ellerslie	2	1.0
Etzikom	33	1.3
Fairydell-Bon Accord	105	0.7
Hamelin Creek	14	0.7
Heart River	2	1.0
Jumping Pound and Sarcee	522	5.8
Medicine Hat	127	3.0
Morinville and St. Albert-Big Lake	155	1.5
Normandville	25	4.8
Okotoks	127	9.3
Rycroft	10	4.0
Stettler and Fenn-Big Valley	67	4.4
Turner Valley	256	6.9
Viking-Kinsella	420	1.8
Wayne-Rosedale	136	1.5
Westlock	251	1.3
Whitelaw	21	4.0
Worsley	158	0.8
Total	3062	
Weighted Average		1.7

Field	Marketable Gas at June 30, 1964	Reserve-Delivery Ratio
	Bcf	Bcf/MMcfd
Oil Field Gas		
Acheson	44	
Bonnie Glen	241	
Campbell-Namao	17	
Glen Park	16	
Judy Creek	213	
Leduc-Woodbend	22	
Pembina	760	
Redwater	46	
Samson	10	
Sturgeon Lake South	67	
Swan Hills	422	
Virginia Hills	50	
Wizard Lake	111	
Total Oil Field Gas	2019	
Weighted Average Reserve-Delivery Ratio for Oil Field Gas		13.9
Reserves Supplying Small Utilities		
Athabasca	4	
Athabasca East	1	
Bantry-Tilley	5	
Bonnyville	2	
Brooks	4	
Brooks North-east	16	
Castor	2	
Cold Lake	2	
Dowling Lake	3	
Duvernay	1	
Elk Point	2	
Fort Kent	3	
Hairy Hill	14	
Holmberg	21	
Jasper Place	5	
Lac La Biche	15	

FIELD	MARKETABLE GAS AT JUNE 30, 1964 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
LEAHURST	8	
LINDBERGH	11	
LLOYDMINSTER	3	
OBERLIN	1	
ST. PAUL	1	
SUFFIELD	18	
WATTS	2	
WILDMERE	9	
WILLINGDON	17	
TOTAL OF RESERVES SUPPLYING SMALL UTILITIES	170	
WEIGHTED AVERAGE RESERVE-DELIVERY RATIO OF RESERVES SUPPLYING SMALL UTILITIES		6,1
TOTAL RESERVES CONNECTED AND SUPPLYING REQUIREMENTS	5251	
WEIGHTED AVERAGE RESERVE-DELIVERY RATIO		2,8

TABLE E-2

MARKETABLE RESERVES AVAILABLE IN THE FIELDS INCLUDED IN PERMITS

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

ALBERTA AND SOUTHERN GAS CO. LTD.

	MARKETABLE RESERVE AT JUNE 30, 1964	RESERVE-DELIVERY RATIO
Field	Bcf	Bcf/MMcfd
Berland River	300	1.2
Brazeau River	156	5.7
Burnt Timber	270	9.7
Caroline	13	2.1
Carson Creek	242	1.6
Carson Creek North	Deferred	-
Crossfield	1026	2.5
Fox Creek	12	1.1
Fox Creek North	8	4.5
Fox Creek West	19	3.2
Homeglen-Rimbey	172	0.8
Kaybob	458	2.0
Lovett River	83	5.5
Minnehik-Buck Lake	429	3.0
Paddle River	160	3.7
Parkland	-	-
Pembina	180	4.6
Stolberg	73	5.5
Waterton	1236	4.0
Westerose South	720	0.5
Wildcat Hills	556	8.1
Windfall, Beaver Creek, and Pine Creek	943	1.6
TOTAL	7056	
WEIGHTED AVERAGE		1.7

CANADIAN-MONTANA GAS COMPANY LTD.

Aden	33
Black Butte	57
Comrey	15
Manyberries	14

CANADIAN-MONTANA GAS COMPANY LTD. (CONT)

Field	MARKETABLE RESERVE AT JUNE 30, 1964 Bcf	RESERVE-DELIVERY RATIO Bcf/MMcfd
Pakowki Lake	7	
Pendant d'Oreille	77	
Smith Coulee	19	
TOTAL	222	
WEIGHTED AVERAGE		3.0
TRANS-CANADA PIPE LINES LIMITED		
Atlee-Buffalo	134	4.1
Bindloss	316	3.3
Carstairs	774	2.5
Cessford	1295	3.0
Chigwell	61	2.1
Connorsville	63	3.6
Countess	159	2.1
Crossfield	17	14.0
Crossfield East	239	1.5
Enchant	33	3.0
Erskine	55	-
Fenn-Big Valley	-	-
Fenn West	6	2.3
Gilby	546	2.0
Hackett	55	3.5
Hamilton Lake	-	-
Harmattan-Elkton	42	1.3
Homeglen-Rimbey	584	0.8
Hussar	440	1.8
Innisfail	84	12.0
Kessler	51	2.5
Lone Pine Creek	108	7.7
Medicine Hat	376	5.5
Minnehik-Buck Lake	-	-
Nevis	576	2.3
Olds	263	4.2
Oyen	34	2.0
Pincher Creek	752	8.8

TRANS-CANADA PIPE LINES LIMITED (CONT)

Field	MARKETABLE RESERVE AT JUNE 30, 1964 Bcf	RESERVE-DELIVERY RATIO Bcf/MMcfd
Prevo	30	4.7
Princess	207	3.0
Provost	435	2.5
Retlaw	44	1.6
Rich	13	1.5
Sedalia	100	7.8
Sibbald	47	3.0
Standard	20	6.2
Stettler	-	-
Sylvan Lake	431	2.0
Three Hills Creek	201	4.7
Verger	45	0.7
Wayne-Rosedale	198	2.5
Westerose South	541	0.5
Wimborne	231	1.0
Wood River	29	2.5
TOTAL	9635	
WEIGHTED AVERAGE		1.9

WESTCOAST TRANSMISSION COMPANY LIMITED (SOUTHERN ALBERTA)

Crossfield	1248	3.0
Savanna Creek	395	20.0
TOTAL	1643	
WEIGHTED AVERAGE		3.7

WESTCOAST TRANSMISSION COMPANY LIMITED(PEACE RIVER)

Belloy	79	3.0
Boundary Lake South	34	1.3
Braeburn	76	5.1
Burnt River	10	2.0
Eaglesham	105	3.5
Gordondale	57	3.1
Pouce Coupe	61	2.8
Pouce Coupe South	58	3.0
Saddle Hills	60	5.0

WESTCOAST TRANSMISSION COMPANY LIMITED (PEACE RIVER) (CONT)

FIELD	MARKETABLE RESERVE AT JUNE 30, 1964 BCF	RESERVE-DELIVERY RATIO BCF/MMCFD
TANGENT	116	8.0
WORSLEY	56	0.8
TOTAL	712	
WEIGHTED AVERAGE		3.1
OTHERS		
ANTELOPE	24	4.9
ESTHER	25	3.7
MEDICINE HAT	722	3.0
WILDUNN CREEK	25	2.0
TOTAL (ALL FIELDS)	20,064	
WEIGHTED AVERAGE (ALL FIELDS)		2.0

TABLE E-3

RESERVES REQUIRED TO MEET PRESENT PERMIT COMMITMENTS

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
	REMAINING PERMIT COMMITMENT									EXCESS GAS IN PERMIT FIELDS	
PERMITTEE	TOTAL BCF	MAXIMUM DAY MMCF	TERMINAL DATE OF PERMIT	RESERVE IN PERMIT FIELDS BCF	RESERVE-DELIVERY RATIO OF PERMIT FIELDS BCF/MMCFD	COMPOSITE CORRECTION FACTOR	MARKETABLE GAS IN PLACE REQUIRED TO MEET TERMINAL PEAK DAY BCF	MARKETABLE GAS REQUIRED TO MEET TERMINAL PEAK DAY BCF	TOTAL MARKETABLE GAS TO MEET PERMIT COMMITMENT BCF	BEFORE TERMINAL DATE BCF	AFTER TERMINAL DATE BCF
ALBERTA AND SOUTHERN GAS CO. LTD.	3966	526	31/10/86	7056	1.7	1.9	1699	1073	5069	1987	3060
CANADIAN-MONTANA GAS COMPANY LTD.	222	100	14/ 3/86	222	-	-	-	-	222	-	-
TRANS-CANADA PIPE LINES LIMITED	7080 (1)	1290	31/10/81 (2)	9635	1.9	1.6	3922	2492	9572	63 (3)	2555 (3)
	1749	-	31/10/89	2555	-	-	-	606	2555	0	806
	8829	1290	31/10/89	9635	-	-	-	806	9635	0	806
WESTCOAST TRANSMISSION COMPANY LIMITED (SOUTHERN ALBERTA)	1034	171	29/ 2/84	1643	3.7	1.5	949	652	1686	-43	609
WESTCOAST TRANSMISSION COMPANY LIMITED (PEACE RIVER)	774	199	31/ 2/79	712	3.1	1.2	740	558	1332	-620	-62
OTHERS	750	167		796	3.0	-	-	46	796	-	46
TOTALS	15605	2453		20064				4811	18740	1324	4459
ROUNDED TOTALS	15600	2450		20100				4800	18700	1400	4500

(1) ANTICIPATED DELIVERIES TO OCTOBER 31, 1981, BASED ON PROJECTED REQUIREMENTS OF TRANS-CANADA PIPE LINES LIMITED.

(2) ESTIMATED DATE TO WHICH WITHDRAWALS AT THE MAXIMUM PERMISSIVE RATE COULD BE MAINTAINED.

(3) EXCESS GAS AS OF OCTOBER 31, 1981.

TABLE E-4

GAS SURPLUS TO ALBERTA'S REQUIREMENTS AND TO EXISTING PERMIT COMMITMENTS

AS OF JUNE 30, 1964

(All volumes in trillions of cubic feet at 1000 Btu per cubic foot)

ESTABLISHED RESERVES

Now considered within economic reach	34.1		
From reserves now considered beyond economic reach (one-half of total)	1.8		
Less: Deferred beyond 30 years	0.5		
Total reserves from present sources		35.4	
From 2 years trends		5.0	
Total reserves available			40.4

RESERVES NEEDED TO MEET REQUIREMENTS AND COMMITMENTS

ALBERTA REQUIREMENTS

Now connected and supplying requirements	5.3		
Required from other sources	5.9		
Required from other sources to meet terminal year peak	4.9		
Total for Alberta requirements		16.1	

PRESENT PERMIT COMMITMENTS

Required to meet commitments	15.6		
Required to meet terminal year peak	3.1		
Total required to meet permit commitments		18.7	
Reserves required to meet Alberta requirements and present permit commitments		34.8	
Less: Reserves released from peak protection after expiry of permits		3.1	
Total reserves needed to meet requirements and commitments			31.7
Surplus before release of reserves required to protect peak day in permits			5.6
Surplus after release of reserves required to protect peak day in permits			8.7

TABLE E-5

COMPARISON OF THE SURPLUSES ESTIMATED BY THE BOARD AND OTHERS

(ALL VOLUMES IN TRILLIONS OF CUBIC FEET AT 1000 BTU PER CUBIC FOOT)

	BOARD (SEPT. 30/63)			ALBERTA AND SOUTHERN (DEC. 31/63)			TRANS-CANADA (APRIL 1/64)			UTILITIES COMPANIES (APRIL 1/64)			BOARD (JUNE 30/64)		
ESTABLISHED RESERVES															
NOW CONSIDERED WITHIN ECONOMIC REACH	31.2			-			33.8			34.0			34.1		
FROM RESERVES NOW CONSIDERED BEYOND ECONOMIC REACH (ONE-HALF OF TOTAL)	1.9			-			1.9			-			1.8		
LESS: DEFERRED BEYOND 30 YEARS	0.5			-			0.5			0.5			0.5		
TOTAL RESERVES FROM PRESENT SOURCES		32.6			32.4			35.2			33.5			35.4	
TREND GAS		3.6			7.5			5.2			-			5.0	
TOTAL RESERVES AVAILABLE			36.2			39.9			40.4			33.5			40.4
RESERVES NEEDED TO MEET REQUIREMENTS AND COMMITMENTS															
ALBERTA REQUIREMENTS															
NOW CONNECTED AND SUPPLYING REQUIREMENTS	5.3			8.7			-			5.3			5.3		
REQUIRED FROM OTHER SOURCES	4.5			-			-			6.2			5.9		
REQUIRED FROM OTHER SOURCES TO MEET TERMINAL YEAR PEAK	4.6			5.6			-			6.3			4.9		
TOTAL ALBERTA REQUIREMENTS		14.4			14.3			14.9			17.8			16.1	
PRESENT PERMIT COMMITMENTS															
REQUIRED TO MEET COMMITMENTS	16.1			15.4			15.8			15.8			15.6		
REQUIRED TO MEET TERMINAL YEAR PEAK	2.5			-			2.5			4.7			3.1		
TOTAL REQUIRED TO MEET PERMIT COMMITMENTS		18.6			15.4			18.3			20.5			18.7	
RESERVES REQUIRED TO MEET ALBERTA REQUIREMENTS AND PRESENT PERMIT COMMITMENTS		33.0			29.7			33.2			38.3			34.8	
LESS: RESERVES RELEASED FROM PEAK PROTECTION AFTER EXPIRY OF PERMITS		2.5			-			2.5			4.7			3.1	
TOTAL RESERVES NEEDED TO MEET REQUIREMENTS AND COMMITMENTS			30.5			29.7			30.7			33.6			31.7
SURPLUS BEFORE RELEASE OF RESERVES REQUIRED TO PROTECT PEAK DAY IN PERMITS			3.2			10.2			7.2			-4.8			5.6
SURPLUS AFTER RELEASE OF RESERVES REQUIRED TO PROTECT PEAK DAY IN PERMITS			5.7			10.2			9.7			-0.1			8.7

APPENDIX F

THE APPLICANTS' REQUESTS FOR AUTHORIZATION FOR THE REMOVAL OF ADDITIONAL QUANTITIES OF GAS AND THE SURPLUS WHICH WOULD RESULT IF THE REQUESTS WERE APPROVED

Trans-Canada requested authorization to remove from Alberta a total of 12,120 billion cubic feet of gas at a maximum daily rate of 1,550 million cubic feet from the fields included in its present permit and from three new fields. For convenience in the study of the meeting of the requested volumes, the Board has converted the quantities to the basis of 1000 Btu per cubic foot. The equivalent volumes become 12,605 billion cubic feet and 1,612 million cubic feet per day. All volumes subsequently referred to in this Appendix will be on the basis of 1000 Btu per cubic foot.

Trans-Canada is authorized under its present permit to remove 10,025 billion cubic feet of which 1,196 have been removed to June 30, 1964. This applicant has in effect requested authority to increase its approved withdrawals from 8,829 to 11,409 billion cubic feet (12,605 - 1,196 = 11,409) as of June 30, 1964.

Alberta and Southern requested authority to remove from the Province a total of 6,837 billion cubic feet of gas at a maximum daily rate of 795 million cubic feet (6,450 billion cubic feet and 750 million cubic feet per day before converting to a 1000 Btu basis) from the fields included in its present permits and from nine new fields.

The applicant has been authorized to remove 4,376 billion cubic feet of which 380 billion cubic feet has been removed to June 30, 1964. Alberta and Southern has requested authority to increase its approved withdrawals from 3,996 to 6,457 billion cubic feet (6,837 - 380 = 6,457) as of June 30, 1964.

As in the previously discussed analysis in Appendix E, the Board studied the manner of meeting the volumes requested by each of the applicants through detailed year by year analysis, although the results are presented using the formula approach.

The results of the Board's analysis is presented in Table F-1 which is identical in form to the previously discussed Table E-3. The table has three lines of entry for each of the applicants: lines 1 and 4 refer to the total volume and peak day requested by each of the applicants, lines 2 and 5 refer to that part of the total volume which the Board believes may be produced at the requested maximum daily rate, and lines 3 and 6 refer to the remaining part of the total volume requested. In the case of Trans-Canada (line 3), the remaining volume requested exceeds the Board's estimate of reserves in the fields in the permit, and therefore, only that quantity remaining in the fields is shown.

Column 1 designates the applicant, while columns 2 and 3 show the total remaining volume and the maximum daily rate requested by each of the applicants. Column 4 presents the expiry date of the requested permits. The Board's present estimate of the total reserves in the fields included in the existing permits and the new fields applied for are shown in column 5. Column 6 shows the Board's estimate of the average reserve-delivery ratio for those reserves shown in column 5. Both of these quantities have been obtained from Table E-2 and from Tables F-2 and F-3 which list the names, reserves, and reserve-delivery ratios for each of the new fields applied for. Column 7 shows the composite correction factors determined from detailed illustrative deliverability schedules. Column 8 presents the quantity of marketable gas in place that would be required to meet the peak day for each of the applicants in the final year in which it can be sustained. The quantities shown in column 8 were obtained from the relationship CFP_n. Column 9 shows the marketable gas equivalent of column 8 and is obtained by deducting from the quantities shown in column 8 the marketable gas equivalent of the gas that will remain in the reservoirs at abandonment. The total marketable gas required to meet the volumes requested and the terminal year peak days is shown in column 10 and is obtained by summing the quantities shown in columns 2 and 9. Columns 11 and 12 show the amounts of gas excess to the quantities requested before and after the expiry date of the permits.

The Trans-Canada Application

It may be seen from line 1 of Table F-1 that for Trans-Canada the total reserves available of some 11,368 billion cubic feet is essentially the same as the requested volume of 11,409 billion cubic feet. Column 11 shows that if protection is provided for both the requested annual volume and terminal year peak day there would be a total deficiency prior to the release of peaking gas of some 3,326 billion cubic feet. The detailed delivery schedules indicate that the reserves as now estimated can deliver the requested maximum quantity of 1,612 million cubic feet per day until some 6,600 billion cubic feet of gas is withdrawn from the fields while maintaining the marketable gas in place of some 6,450 billion cubic feet required to sustain the peak day demand. This is illustrated in line 2 of the table. If the gas is removed in accordance with the requirements projected by Trans-Canada, the requested peak will be sustained until approximately the end of 1980. At this time, marketable reserves of some 4,749 billion cubic feet would still be available in the fields requested. This additional amount of gas may be included in the quantity approved for removal from the Province (as is illustrated in line 3) but no assurance can be given that the gas can be produced during the remainder of the twenty-five year period at the requested rates.

Since all permits for the removal of gas from Alberta have been issued on an as is basis, rather than a 1000 Btu basis, the volumes previously referred to must be converted to the basis of 14.65 pounds per square inch absolute and 60 degrees Fahrenheit. The volume of gas which could be produced at full rates by Trans-Canada would be some 6,364 billion cubic feet, and the remaining volume which would be produced thereafter is equivalent to some 4,566 billion cubic feet at 14.65 pounds per square inch and 60 degrees Fahrenheit.

The Alberta and Southern Application

In the case of the Alberta and Southern application, the total available reserve of some 7,798 billion cubic feet is in excess of the requested volume of 6,457 billion cubic feet. However, there is a deficiency of some 750 billion cubic feet in reserves required to meet both the annual volumes and the terminal year peak day. The deliverability schedules indicate that the reserves as now estimated are not able to deliver the requested maximum quantity of 795 million cubic feet per day during the entire period, but that some 5,900 billion cubic feet of gas could be withdrawn from the fields while maintaining the marketable gas in place of some 2,862 billion cubic feet needed to sustain the peak day demand. This is illustrated in line 5 of Table F-1 and represents the quantity of gas that would be withdrawn up to approximately the end of 1988. At that time, marketable reserves of some 1,898 billion cubic feet would still be available in the permit fields. The Board believes that the remaining portion of Alberta and Southern's request, 557 billion cubic feet (6,457 - 5,900 = 557) could be produced during the remainder of the requested period at less than the requested maximum delivery rates. These volumes (5,900 and 557 billion cubic feet) when converted to the basis of 14.65 pounds per square inch absolute and 60 degrees Fahrenheit, become 5,566 billion cubic feet and 525 billion cubic feet.

Surplus If Present Applications Were Granted

Should the additional volumes requested by each of the applicants be authorized for removal from the Province, the Board estimates that the provincial gas surplus before the release of reserves required for the protection of the peak day quantities specified in all permits would be reduced from the 5.4 trillion cubic feet shown in Table D-4 to some 0.9 trillion cubic feet. After the expiry dates for the various permits, an additional 2.6 trillion cubic feet of gas would be released from terminal year peak day protection increasing the surplus to some 3.5 trillion cubic feet.

The manner in which the new surplus was calculated is shown in Table F-4. The figure for total reserves available has been taken from Table E-4. The reserve needed to meet Alberta's requirements has also been taken from Appendix E, but includes the Trunk Line pipe line fuel and the shrinkage that would be associated with the additional quantities of gas requested by both applicants. The reserves required to meet the existing and the applied for permit commitments have been taken from Tables E-3 and F-1.

TABLE F-1

RESERVES REQUIRED TO MEET THE REQUESTS OF TRANS-CANADA PIPE LINES LIMITED AND ALBERTA AND SOUTHERN GAS CO. LTD.

(All volumes at 1000 Btu per cubic foot)

APPLICANT	REMAINING VOLUMES REQUESTED BCF	PEAK DAY REQUESTED MMCF	TERM OF REQUEST	RESERVES IN FIELDS BCF	RESERVE-DELIVERY RATIO BCF/MMCFD	COMPOSITE CORRECTION FACTOR	MARKETABLE GAS IN PLACE TO MEET PEAK DAY REQUESTED BCF	MARKETABLE GAS REQUIRED TO MEET PEAK DAY REQUESTED BCF	TOTAL MARKETABLE GAS REQUIRED TO MEET REQUEST BCF	BEFORE EXPIRY DATE BCF	AFTER EXPIRY DATE BCF
Trans-Canada Pipe Lines Limited	11409	1612	31/10/89	11368	2.0	1.7	5481	3285	14694	-3326	-41
	6619	1612		11368	2.0	2.0	6448	4749	11368	0(1)	4749(1)
	4749	-	31/10/89	4749	-	-	-	-	4749	0	0
Alberta and Southern Gas Co. Ltd.	6457	795	31/10/89	7798	1.8	2.2	3148	2091	8548	-750	1341
	5900	795		7798	1.8	2.0	2862	1898	7798	0(2)	1898(2)
	557	-	31/10/89	1898	-	-	-	-	557	1341	1341

(1) Before and after the removal of 6619 Bcf of gas.

(2) Before and after the removal of 5900 Bcf of gas.

TABLE F-2

MARKETABLE RESERVES IN FIELDS APPLIED FOR BY TRANS-CANADA PIPE LINES LIMITED

(ALL VOLUMES AT 1000 BTU PER CUBIC FOOT)

	MARKETABLE GAS AT JUNE 30, 1964	RESERVE-DELIVERY RATIO
FIELD	BCF	BCF/MMCFD
EDSON	1564	2.2
HESPERO	63	2.1
MEDICINE RIVER	106	3.4
TOTAL	1,733	
WEIGHTED AVERAGE		2.3

TABLE F-3

MARKETABLE RESERVES IN FIELDS APPLIED FOR BY ALBERTA AND SOUTHERN GAS CO. LTD.

(ALL VOLUMES AT 1000 Btu PER CUBIC FOOT)

Field	MARKETABLE GAS AT JUNE 30, 1964 Bcf	RESERVE-DELIVERY RATIO Bcf/MMcfd
Bigstone	289	5.1
Caroline	28	1.8
Hunter Valley	54	1.9
Pine North-west	105	2.8
Sundre	53	10.0
Sylvan Lake	7	2.1
Wildhorse creek	94	4.5
Willesden Green	74	8.0
Wilson Creek	38	1.0
TOTAL	742	
WEIGHTED AVERAGE		3.1

TABLE F-4

SURPLUS AS OF JUNE 30, 1964
IF PRESENT APPLICATIONS WERE GRANTED

(ALL VOLUMES IN TRILLIONS OF CUBIC FEET AT 1000 BTU PER CUBIC FOOT)

TOTAL RESERVES AVAILABLE (FROM TABLE D-4)			40.4
REQUIREMENTS AND COMMITMENTS			
TOTAL RESERVES NEEDED TO MEET ALBERTA REQUIREMENTS (FROM TABLE D-4)		16.3	
PERMIT COMMITMENTS			
RESERVES REQUIRED TO MEET COMMITMENTS	20.6		
RESERVES REQUIRED TO MEET TERMINAL YEAR PEAK	2.6		
TOTAL RESERVES REQUIRED TO MEET COMMITMENTS		23.2	
RESERVES REQUIRED TO MEET ALBERTA REQUIREMENTS AND PERMIT COMMITMENTS		39.5	
LESS: RESERVES RELEASED FROM PEAK PROTECTION AFTER EXPIRY OF PERMITS		2.6	
TOTAL RESERVES REQUIRED TO MEET REQUIREMENTS AND COMMITMENTS			36.9
SURPLUS BEFORE RELEASE OF GAS REQUIRED TO PROTECT PEAK DAY IN PERMITS			0.9
SURPLUS AFTER RELEASE OF GAS REQUIRED TO PROTECT PEAK DAY IN PERMITS			3.5

APPENDIX G

OTHER PERMIT AMENDMENTS REQUESTED BY THE APPLICANTS

Both Trans-Canada and Alberta and Southern requested certain permit amendments which have not been previously discussed in this report. These matters are considered in this Appendix and are discussed under the following headings:

(a) Daily Volume Limitations of the Alberta and Southern Permits.

(b) Extension of Period of the Existing Permits of Alberta and Southern.

(c) Consolidation of the Permits of Alberta and Southern.

(d) Consolidation of the Permits of Trans-Canada.

(e) Deletion of the Parkland Field from the Alberta and Southern Permit.

Daily Volume Limitations of the Alberta and Southern Permits

Alberta and Southern requested that for the purpose of alleviating temporary operating problems caused by pipe line or equipment failure, the quantity of gas that may be removed from the Province in any one day be increased to 110 per cent of the volume of gas that may normally be removed in any one day in accordance with the existing permits. This request was not questioned by anyone during the hearing of the application.

The Board recognizes the desirability of some flexibility for the operating problems mentioned by the applicant. Following the hearing of the Trans-Canada application of September 23, 1963, the Board granted such flexibility to Trans-Canada in its Permit No. TC 64-5 and believes the same flexibility should be granted to Alberta and Southern.

Extension of Period of the Existing Permits of Alberta and Southern

Each of the two permits held by Alberta and Southern expires on October 31, 1986. The applicant requested that the term of the permits be extended to October 31, 1989.

Mr. Blair, representing Alberta and Southern, stated that the applicant is now purchasing gas on a twenty-five year contract basis from fields which are within the present permits, and that these contracts would extend beyond the term of the present permits. He also stated that gas will remain in the fields and pools named in the applicant's permits after 1986, and in order to remove this gas an extension of the permit period would be necessary.

The first such request for the extension of the term of a permit was received from Trans-Canada during the hearing of its application of September, 1963. The details of the Board's views, concerning such requests are contained in Appendix F of OGCB Report 64-1, dated February, 1964.(1)

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(1) Report to The Lieutenant Governor in Council with respect to an Application of Trans-Canada Pipe Lines Limited under The Gas Resources Preservation Act, 1956.

In the case of the present application, the Board in keeping with its decision to extend an initial permit period to a maximum of twenty-five years to correspond to the contract year, believes the existing Alberta and Southern permits should be extended to October 31, 1989. In extending the period of the permits, the Board recognizes that the additional gas requested from fields now under permit may not be producible for the full period of the extension at the maximum daily rates possible under terms of the permit.

Consolidation of the Permits of Alberta and Southern

Alberta and Southern holds two permits each authorizing the removal of gas in specified volumes from a field or a group of fields. The applicant requested consolidation of the two existing permits into one, for the sake of operating convenience. The Board, as is discussed in its report of February, 1964, consolidated the Trans-Canada permits into one permit.

Since contract volumes are continually being revised due to redeterminations of reserves resulting in increases or decreases of reserves under contract and because new contracts are entered into upon further field developments, flexibility in removing gas from the Province is reduced by individual permit limitations. For this reason and for the purpose of administration, the Board believes that consolidation of the permits is desirable. Such consolidation would not lessen the protection for Alberta consumers and accordingly the Board is prepared to consolidate the existing permits of Alberta and Southern into one permit.

Consolidation of the Permits of Trans-Canada

Trans-Canada requested that if a permit for the removal of gas from the Edson, Hespero and Medicine River fields be granted, such a permit be consolidated with the existing Permit No. TC 64-5 amended pursuant to its application, into one permit.

For the reasons previously stated, the Board is prepared to consolidate these permits.

Deletion of the Parkland Field from the Alberta and Southern Permit

The applicant requested that the Parkland Field be deleted from one of its permits since it has become apparent that there will be no further gas supply from that field.

The Board concurs with the applicant that the Parkland Field has become incapable of gas production and, therefore, believes that this field should be deleted from the permit. The amount of gas reserves in the permit fields excess to the permit quantities is greater than the reserves previously attributed to Parkland. For this reason, no reduction is necessary in the quantities approved for removal from the Province.

APPENDIX H

IN THE MATTER of The Gas Resources Preservation Act, 1956, being chapter 19 of the Statutes of Alberta, 1956; and

IN THE MATTER of a Permit to Trans-Canada Pipe Lines Limited authorizing the removal of gas from the Province.

PERMIT NO. TC 64-6

WHEREAS Trans-Canada Pipe Lines Limited (herein called "the Permittee"), is removing gas from the Province under authority of Permit No. TC 64-5; and

WHEREAS the Permittee has applied to the Oil and Gas Conservation Board for an increase in the volumes of gas that it may remove or cause to be removed from the Province, and for amendment and consolidation of the permit it now holds and the permit applied for; and

WHEREAS the Board upon inquiry into and hearing of the application has found that the applicant is a person who purchases gas within the Province and who has entered into contracts to purchase gas within the Province and who proposes to cause such gas to be removed from the Province and that the provisions of The Gas Resources Preservation Act, 1956, affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of this Permit for the removal of gas from the Province is in the public interest having regard to the present and future needs of persons within the Province, and to the established reserves and trends in growth and discovery of the reserves of gas in the Province; and

WHEREAS the Lieutenant Governor in Council has given his approval by Order in Council numbered O.C. ________ and dated ______________________.

THEREFORE, the Oil and Gas Conservation Board, pursuant to the provisions of The Gas Resources Preservation Act, 1956, being chapter 19 of the Statutes of Alberta, 1956, hereby grants a permit to Trans-Canada Pipe Lines Limited, and hereby authorizes the removal of gas from the Province, subject to the regulations and orders made pursuant to the provisions of the said Act and to the terms and conditions prescribed in this Permit, as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this Permit shall be operative for a term commencing on the date hereof and ending on October 31, 1989.

2. The quantity of gas that may be removed from the Province pursuant to this Permit shall not exceed,

(a) until the cumulative volume removed under this Permit and Permits numbered TC 54-1, TC 59-2, TC 60-3, TC 60-4 and TC 64-5 is 7,515,000,000,000 cubic feet, 1,550,000,000 cubic feet in any consecutive twenty-four hour period or 525,000,000,000 cubic feet in any consecutive twelve-month period,

(b) after the cumulative volume removed under the Permits referred to in subclause (a) reaches 7,515,000,000,000 cubic feet and until October 31, 1989, in any consecutive twelve-month period such quantities equal to or less than those prescribed in subclause (a) as may be limited by field productivity and good engineering practice, and

(c) during the term of the Permit, that quantity of gas which together with the gas removed under Permit No. TC 54-1, Permit No. TC 59-2, Permit No. TC 60-3, Permit No. TC 60-4 and Permit No. TC 64-5 shall total not more than 12,080,000,000,000 cubic feet.

3. Notwithstanding the provisions of clause 2, subclause (a), the Permittee, for the purpose only of alleviating temporary operating problems caused by pipe line or equipment failure, may remove in any consecutive twenty-four hour period 110 per cent of the volume of gas authorized by said subclause (a).

4. The Permittee, for the purpose of this Permit, may purchase or otherwise acquire for removal from the Province, and subject to clause 5 there may be removed from the Province under

the authority of this Permit, only gas produced from the following pools, fields and areas:

Atlee-Buffalo Field
Bindloss Field
Carstairs Field
Cessford Field
Chigwell Field
Connorsville Field
Countess Field
Crossfield Cardium Pool
Crossfield East Field
Edson Field
Enchant Field
Erskine Field
Fenn-Big Valley Field
Fenn West Field
Gilby Field
Hackett Field
Hamilton Lake Field
Harmattan-Elkton Rundle A Pool
Hespero Field
Homeglen-Rimbey Field
Hussar Field
Innisfail Field
Kessler Field
Lone Pine Creek Field
Medicine River Field

Minnehik-Buck Lake Field

Nevis Field

Olds Field

Oyen Field

Pincher Creek Field

Prevo Field

Princess Field

Provost Field

Retlaw Field

Rich Field

Sedalia Field

Sibbald Field

Standard Field

Stettler Field

Sylvan Lake Field

Three Hills Creek Field

Verger Field

Wayne-Rosedale Field

Westerose South Field

Wimborne Field

Wood River Field

The area in the Medicine Hat Field being north of Sections 1, 2, 3, 4, 5, and 6, in Township 15, and in Ranges 1, 2 and 3, West of the Fourth Meridian, excepting therefrom Section 7, Township 15, Range 2, West of the Fourth Meridian.

5. Gas acquired in Alberta by the Permittee, in exchange for equal volumes of gas, adjusted for any difference in higher heating value, produced from pools, fields or areas named in clause 5, may be removed from the Province under the authority of this Permit.

6. The Permittee shall remove or cause to be removed pursuant to this Permit only such gas as is delivered to it through facilities of The Alberta Gas Trunk Line Company Limited at the interconnection of their pipe lines in the North-east quarter of Section 11, Township 20, Range 1, West of the Fourth Meridian.

7. (1) All gas removed from the Province pursuant to this Permit shall be measured by or on behalf of the Permittee by master meters approved by the Board and located at the point at which gas is delivered by The Alberta Gas Trunk Line Company Limited to the Permittee.

(2) The specific gravity and higher heating value of all gas received by the Permittee through the facilities of The Alberta Gas Trunk Line Company Limited shall be measured by or on behalf of the Permittee at the point at which gas is delivered by The Alberta Gas Trunk Line Company Limited to the Permittee.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

8. Subject to section 14 of the said Act, all quantities of gas for the purpose of this Permit shall be referred to a 14.65 pounds per square inch absolute pressure base and a 60 degree Fahrenheit temperature base.

9. Notwithstanding the provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this Permit.

10. The Permittee will supply gas from the pipe line of The Alberta Gas Trunk Line Company Limited at a reasonable price to any community or consumer within the Province, or to any public utility requiring gas for such a community or consumer, that is willing to take delivery of gas at a point on the pipe line, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

11. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 10 of these terms and conditions, and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

12. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, competent regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

13. Permit No. TC 64-5 is rescinded.

MADE at the City of Calgary, in the Province of Alberta, this day of A.D. 1964.

OIL AND GAS CONSERVATION BOARD,

G. W. Govier,
Chairman.

APPENDIX I

IN THE MATTER of The Gas Resources Preservation Act, 1956, being chapter 19 of the Statutes of Alberta, 1956; and

IN THE MATTER of a Permit to Alberta and Southern Gas Co. Ltd. authorizing the removal of gas from the Province.

PERMIT NO. AS 64-3

WHEREAS Alberta and Southern Gas Co. Ltd. (herein called "the Permittee"), is removing gas from the Province under authority of Permits Numbered AS 59-1 and AS 60-2; and

WHEREAS the Permittee has applied to the Oil and Gas Conservation Board for an increase in the volumes of gas that it may remove or cause to be removed from the Province, and for amendment and consolidation of the permits it now holds and the permit applied for; and

WHEREAS the Board upon inquiry into and hearing of the application has found that the applicant is a person who purchases gas within the Province and who has entered into contracts to purchase gas within the Province and who proposes to cause such gas to be removed from the Province and that the provisions of The Gas Resources Preservation Act, 1956, affecting the application have been complied with; and

WHEREAS the Board is of the opinion that the granting of this Permit for the removal of gas from the Province is in the public interest having regard to the present and future needs of persons within the Province, and to the established reserves and trends in growth and discovery of the reserves of gas in the Province; and

WHEREAS the Lieutenant Governor in Council has given his approval by Order in Council numbered O.C.___________ and dated__________________.

THEREFORE, the Oil and Gas Conservation Board, pursuant to the provisions of The Gas Resources Preservation Act, 1956, being chapter 19 of the Statutes of Alberta, 1956, hereby grants a permit to Alberta and Southern Gas Co. Ltd., and hereby authorizes the removal of gas from the Province, which gas includes gas that is the property of the Permittee at the time of removal and gas that has been sold by the Permittee to Canadian-Montana Pipe Line Company prior to removal, subject to the regulations and orders made pursuant to the provisions of the said Act and to the terms and conditions prescribed in this Permit, as follows:

1. Subject to the conformity by the Permittee with the terms and conditions hereof, this Permit shall be operative for a term commencing on the date hereof and ending on October 31, 1989.

2. The quantity of gas that may be removed from the Province pursuant to this Permit shall not exceed,

   (a) until the cumulative volume removed under this Permit and Permits numbered AS 59-1 and AS 60-2 is 5,925,000,000,000 cubic feet, 750,000,000 cubic feet in any consecutive twenty-four hour period or 250,000,000,000 cubic feet in any consecutive twelve-month period,

(b) after the cumulative volume removed under the Permits referred to in subclause (a) reaches 5,925,000,000,000 cubic feet and until October 31, 1989, in any consecutive twenty-four hour period or in any consecutive twelve-month period such quantities equal to or less than those prescribed in subclause (a) as may be limited by field productivity and good engineering practice, and

(c) during the term of the Permit, that quantity of gas which together with the gas removed under Permit No. AS 59-1 and Permit No. AS 60-2 shall total not more than 6,450,000,000,000 cubic feet.

3. Notwithstanding the provisions of clause 2, subclause (a), the Permitee, for the purpose only of alleviating temporary operating problems caused by pipe line or equipment failure, may remove in any consecutive twenty-four hour period 110 per cent of the volume of gas authorized by said subclause (a).

4. The Permittee, for the purpose of this Permit, may purchase or otherwise acquire for removal from the Province, and subject to clause 5 there may be removed from the Province under the authority of this Permit, only gas produced from the following pools, field and areas:

Beaver Creek Field

Berland River Field

Bigstone Field

Brazeau River Field

Burnt Timber Field

Caroline Field

Carson Creek Field

Carson Creek North Field

Crossfield Rundle Pool

Fox Creek Field

Fox Creek North Field

Fox Creek West Field

Homeglen-Rimbey Field

Hunter Valley Field

Kaybob Field

Lovett River Field

Minnehik-Buck Lake Field

Paddle River Field

Pembina Lobstick Glauconitic Pool

Pembina Lobstick Ostracod Pool

Pine Creek Field

Pine North-west Field

Stolberg Field

Sundre Field

Sylvan Lake Field

Waterton Field

Westerose South Field

Wildcat Hills Field

Wildhorse Creek Field
Willesden Green Field
Wilson Creek Field
Windfall Field

5. Gas acquired in Alberta by the Permittee, in exchange for equal volumes of gas, adjusted for any difference in higher heating value, produced from pools, fields or areas named in clause 4, may be removed from the Province under the authority of this Permit.

6. The Permittee shall remove or cause to be removed pursuant to this Permit only such gas as is delivered through the facilities of The Alberta Gas Trunk Line Company Limited

(a) to the pipe line of Alberta Natural Gas Company on behalf of the Permittee, at the interconnection of the said facilities and pipe line at a location in Section 17, Township 8, Range 5, West of the 5th Meridian approved by the Board, or

(b) to the pipe line of Canadian-Montana Pipe Line Company for sale by the Permittee to Canadian-Montana Pipe Line Company, at the interconnection of the said facilities and pipe line at a location in Township 1, Range 26, West of the 4th Meridian approved by the Board.

7. (1) All gas removed from the Province pursuant to this Permit shall be measured by or on behalf of the Permittee by

master meters approved by the Board and located at the points at which gas is delivered in accordance with clause 6, and in the event that other gas is measured by such a meter, the part of the measured gas that is being removed pursuant to this Permit shall be determined in a manner approved by the Board.

(2) The specific gravity and higher heating value of all gas received by the Permittee through the facilities of The Alberta Gas Trunk Line Company Limited shall be measured by or on behalf of the Permittee at the points at which gas is delivered by The Alberta Gas Trunk Line Company Limited to the Permittee.

(3) The measurements required by this clause shall be made in a manner approved by the Board and shall be reported monthly in a manner approved by the Board.

8. Subject to section 14 of the said Act, all quantities of gas for the purpose of this Permit shall be referred to a 14.65 pounds per square inch absolute pressure base and a 60 degree Fahrenheit temperature base.

9. Notwithstanding the provisions of any contract for the purchase or other acquisition of gas, the Board may require the extraction of any substance or substances except methane from any gas before its removal from the Province pursuant to this Permit.

10. The Permittee will supply gas from the pipe line of The Alberta Gas Trunk Line Company Limited at a reasonable price

to any community or consumer within the Province, or to any public utility requiring gas for such a community or consumer, that is willing to take delivery of gas at a point on the pipe line, and that, in the opinion of the Board, can reasonably be so supplied by the Permittee.

11. If any community, consumer or public utility is willing to take delivery of gas pursuant to clause 10 of these terms and conditions, and agreement on the price to be paid for the gas cannot be reached, the price to be paid shall be determined by the Public Utilities Board on the application of an interested party, and the part of the price attributable to transportation shall be based on the assumption that the gas has been supplied from the capable source or sources available to the Permittee nearest to the point of delivery.

12. Notwithstanding the provisions hereof, the Permittee shall comply with the provisions of any Act, competent regulation, order or direction governing the drilling for, production, conservation, gathering, transportation, processing, purchasing, acquisition, sale, measurement, reporting, testing, supply or delivery of gas within the Province.

13. Permit No. AS 59-1 and Permit No. AS 60-2 are rescinded.

MADE at the City of Calgary, in the Province of Alberta, this day of A.D. 1964.

OIL AND GAS CONSERVATION BOARD,

G. W. Govier,

Chairman.